THE EFFECTS OF CLIMATE CHANGE ON ELECTRICITY GENERATION AND FUEL SUPPLY IN 2050: A STUDY OF LOUISIANA, CALIFORNIA, NEW YORK, AND WASHINGTON'S CONVENTIONAL GRID

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THE EFFECTS OF CLIMATE CHANGE ON ELECTRICITY GENERATION AND FUEL SUPPLY IN 2050: A STUDY OF LOUISIANA, CALIFORNIA, NEW YORK, AND WASHINGTON'S CONVENTIONAL GRID

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LIST OF SYMBOLS AND ABBREVIATIONS

EDF	Environmental Defense Fund
EIA	Energy Information Administration
IPCC	Intergovernmental Panel on Climate Change
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
PRM	Planning Reserve Margin
US	United States
WEFOR	Weighted-Equivalent Generation Forced Outage Rate

SUMMARY

Climate change due to increased greenhouse gas emissions can impact energy infrastructure in a variety of ways. Climate impacts on power grid reliability in 2050 for Louisiana, California, New York, and Washington were studied in this paper. Projected electric loads, reserve margins, ramping needs, and flexible reserves were calculated for each state in 2050 to form a baseline to analyze the effect of extreme temperatures and drought on electricity generation and fuel supply, which can in turn impact grid reliability. Reduced capacity of natural gas combined cycle power plants from increased heat, combined with increased electrical demand, is projected to affect all states, especially California and Louisiana. These states also are projected to have some of the most severe heat in the country in 2050. Reduced thermal plant capacity from increased cooling water temperatures or low cooling water supply is an issue, however its effects on in-state generation in these states is projected to be minimal. Decreases in hydropower generation are also projected to have minimal effect on all states, however it had the greatest impact on California. Lastly, natural gas supply loss is projected to impact all states, especially Louisiana and California. Overall, geographic location, seasons, time of day, fuel mix, and policy are all factors to be considered when analysing the effects of climate change on the reliability of the power grid.

CHAPTER 1. INTRODUCTION

1.1 Climate Change Effects

Climate change, caused by increasing greenhouse gas emissions throughout the world, has, and will continue to have, deleterious effects on energy infrastructure in the US (Romero-Lankao et al., 2014). According to the IPCC's fifth assessment report, the US has experienced severe heat events, fewer frost days, and increased intense precipitation at greater rates because of climate change (Romero-Lankao et al., 2014). The frequency and severity of these events is expected to increase in the coming years (Romero-Lankao et al., 2014). Additionally, the US will experience higher sea levels combined with increased storm frequency, more frequent and intense droughts, and unpredictability in rainfall patterns (Romero-Lankao et al., 2014). These effects have the potential to impact the current electricity generation and transmission systems in the US.

1.2 The Conventional Power Grid

This paper will focus on climate change effects on the conventional power grid in the US, with a focus on four states: Louisiana, California, New York, and Washington. Here we define the conventional grid as centralized points of generation (i.e., power plants) and the transmission and distribution system that connects them to customers. These centralized points of generation require the presence of a fuel source, whether that be natural gas, coal, water, wind, solar, etc., to generate electricity. After the point of generation, electricity moves through a network of substations, transmission, and distribution lines, in which it is then delivered to the customer. In the US, as of 2019, there are over 10,000 power plants, nearly 700,000 miles of transmission lines, 6.3 million miles of distribution lines, and 22,000 substations (EIA, 2020a). These extensive infrastructure systems are susceptible to environmental stressors brought on by climate change. This paper will expand on climate change effects on thermal and hydroelectric power plants, as well as effects specific to natural gas as fuel source.

1.2.1 Thermal power plants

Thermal power plants utilize heat to generate electricity. These plants can use nuclear, biomass, natural gas, coal, or other fuel sources to provide heat to create steam. These steam plants then require a medium to condense the steam created during combustion. Typically, this cooling has been achieved using water. The electric power generation sector accounts for 40% of water withdrawals in the US (Grubert & Sanders, 2018). Water, usually from a nearby surface water source, is withdrawn, used to cool and condense the steam, and the majority is then released back into the water source. This is known as once through cooling. Recirculating cooling systems intake water, and once it is used, it is stored in a cooling tower, or other mechanism, to cool. It is then reused to condense steam once it cools to a proper temperature. This type of system withdraws much less water from the source than a once through system. A newer type of cooling system is dry cooling. This system uses significantly less water (95%), but instead uses cool air to condense steam (Ray, 2018). It is less efficient than water-based cooling systems, however in areas where there are water supply constraints, it is gaining traction. The majority of thermal power plants, 61%, use recirculating cooling systems (Ray, 2018).

1.2.2 Natural gas

Natural gas is used to generate about a third of the electricity in the US, however only about 20-30% of consumed natural gas is used to generate electricity as there are other uses for the fuel itself (EIA, 2020b). This includes for heating and cooking in the residential and commercial sector, as well as for industrial uses and as a transportation fuel (EIA, 2020b). Natural gas is processed and transported through pipelines to be delivered to power plants for electricity generation, or directly to the customer.

1.2.3 Hydroelectric plants

Hydroelectric power plants do not utilize a heat source, but instead utilize moving water to produce electricity (EIA, 2021). Hydropower is considered a renewable source of electricity as it relies on the natural hydrologic cycle of water bodies as its fuel. Flow of water in rivers, or the falling of water from a reservoir, is harnessed to turn a turbine and generate electricity (EIA, 2021).

1.3 Grid Reliability

As electricity is generated and consumed instantaneously, it is important to maintain an equal supply and demand. An imbalance will cause brownouts or blackouts, and widespread power outages greatly affect residents, businesses, and services that all depend on electricity (Wang, 2019). As modern society increasingly relies on electricity, an unreliable power grid will negatively impact those living and working within it. This becomes even more apparent as extreme temperature events are instances in which electric cooling and heating demands are at their highest and most needed. IPCC’s fifth assessment report specifies that there is currently little “proactive adaptation” to the impacts of climate change, specifically in the energy industry (Romero-Lankao et al., 2014). Therefore, long term planning for these effects is pertinent.

1.4 Research Gap

Current literature, as discussed further below, has focused on the effects climate change can have on hydropower, fossil fuel, and thermal power plants, however little has been done to combine future electric loads, climate trends, and climate effects on these systems in the future, specifically on an hourly basis.

Specific climate change impacts on hydropower generation have been studied at a global scale (Hamududu & Killingtveit, 2012), US scale (Kao et al., 2015), and regional scale (Madani & Lund, 2010; Markoff & Cullen, 2008). Regional and seasonal differences have been compounded and studied as well (Boehlert et al., 2016; Sale et al., 2012). However, these studies do not incorporate daily changes in load to see when climate change impacts on hydropower have the potential to make the bulk power system most vulnerable.

Similar studies have been performed on the impacts on thermoelectric power plants. These include at the global scale (Van Vliet et al., 2016), US scale (van Vliet & Ludwig, 2012), and plant scale (Forster et al., 2010; Sieber, 2013).

It has also been studied that climate change will likely increase electricity demand (Allen et al., 2016; McFarland et al., 2015; Sailor, 2001).

Few studies have compounded the effects of climate, increased demand, and fuel mix changes on the grid. Studies have been done at the US (Craig et al., 2018) and regional scales (Miara et al., 2017; Ralston Fonseca et al., 2021). None of these, however, incorporate these effects on hourly loads at the state level.

This paper will focus on the climate change effects of extreme temperatures and drought on generator reliability of the conventional grid, specifically thermo and hydroelectric power plants. I will focus my analysis on the projected 2050 electricity demand and generation for four states in the US: Louisiana, California, New York, and Washington using NREL's Cambium (*Cambium | Standard Scenarios 2020 | Cambium Scenarios (Hourly and Annual Data)*, n.d.). These four states are located in four distinct regions of the country, all of which will be affected by climate change to various degrees. These states also have different electricity demands, fuel mixes, and policies that will shape their future generation system.

In chapter 2, I will focus on what effects of climate change can impact energy infrastructure, how climate change can affect the conventional grid and thermo and hydroelectric generation, the current issues relating to grid reliability, and how this topic is relevant in the US at this time.

In chapter 3, I will outline the methods used to perform forecasting analyses for each state incorporating certain climate change effects on fuel supply and power generation.

In chapter 4 and 5, I will present my results and discuss the characteristics of each state that could impact their future grid reliability, such as daily load curves, ramping needs, and potential reserves. Additionally, I will discuss the potential vulnerabilities of each state's thermal and hydroelectric power plants from the impacts of the increased heat, cold, and drought that is possible due to climate change.

CHAPTER 2. BACKGROUND

2.1 Climate Change Effects on the Conventional Grid

As the conventional power grid relies on multiple physical systems or resources, such as fossil fuels, thermal power plants, transmission lines, etc., the effects of climate change can impact these systems in a variety of ways. This chapter investigates droughts, extreme temperatures, and storms as key examples of such impacts.

2.1.1 Droughts

Thermoelectric generation, specifically plants that use wet cooling systems, require a significant amount of water to operate; 40% of water withdrawals in the US are for electricity generation (Grubert & Sanders, 2018). Increased droughts or fluctuation in surface water supplies will affect the availability of this water. Lower water levels at the source can make generation less efficient (Argonne National Laboratory, 2012). 43% of thermal plants in the US have intake heights for their cooling water supply at less than ten feet below the typical water height of the source (Dumas et al., 2019). A few feet of variation for a thermal plant's water supply source can translate to minimal or no ability for a plant to meet its cooling water needs. This point was illustrated in the summer of 2012 when a power plant in the Midwest shut down as its water supply fell below the height of its intake pipes (Eaton, 2012).

Hydroelectric plants are also affected by drought or changing patterns in the water cycle. Lower rates of stream flow or lower water levels in reservoirs correlate to lower power output (Kao et al., 2015). Currently, forecasted low flow levels in the Colorado River are projecting low water levels in Lake Mead, the location of the Hoover Dam (Metz, 2021). These low levels are expected to reduce the generation of the Hoover Dam in the coming months.

Even if water is not the "fuel" used for generation, it is still an integral part of electricity generation for the conventional grid. Increased droughts and decreased precipitation can affect the ability of thermal and hydro power plants to generate electricity.

2.1.2 Extreme temperatures

According to the IPCC's fifth assessment report, it is "very likely" (90-100% probability) that the temperature has increased throughout North America in the past century and the US has experienced an increase in severe heat events (Romero-Lankao et al., 2014). For natural gas-fired power plants, increased ambient air temperatures can reduce their efficiency (Petrakopoulou et al., 2020). Additionally, increased temperatures of cooling water sources can reduce the capacity of thermal power plants (van Vliet & Ludwig, 2012). In the summer of 2012, a nuclear reactor in Connecticut was forced to shut down as temperatures of the Long Island sound, its cooling water source, were too high (Eaton, 2012). Extreme heat events lead to increased electricity demand, further stressing equipment that is already performing under reduced capacity (Dumas et al., 2019). Thermoelectric generation is susceptible to the effects of extreme heat events, however electricity needs are likely to be highest during these times.

Extreme cold events can also have negative consequences. Natural gas production can cease at the wellhead if cold temperatures freeze water or other liquids that are present in natural gas in the well or in gathering lines before processing (York, 2021). This freezing will block the flow of gas for processing and delivery. Without sufficient gas supply, natural gas-fired power plants are at risk of shutting down during these times. Additionally, equipment at power plants that are not winterized can freeze and cause generators to trip offline. This was seen in the 2011 Texas power outage, which will be discussed further in section 2.3.1.

Extreme heat and cold can also affect the transmission and distribution systems. Increased temperatures can increase energy losses and reduce capacity ratings for transmission and distribution cables (Argonne National Laboratory, 2012) (Ward, 2013). They can also accelerate the aging of electrical equipment, as well as lead to equipment failure because of the increased demand loads that the equipment is not designed to handle (Dumas et al., 2019). Under icy conditions, ice on overhead lines can cause them to collapse (Dumas et al., 2019).

2.1.3 Storms

Transmission and distribution infrastructure mainly consists of overhead power lines that are susceptible to the environment. Increased frequency of storms and/or more severe storms can impact the transmission and distribution systems by damaging overhead lines from flying debris or downed poles (Dumas et al., 2019) (Ward, 2013). Additionally, flooding and/or sea level rise can damage electrical equipment at substations or underground cables (Dumas et al., 2019) (Ward, 2013).

2.2 Current State of Reliability

NERC, the North American Electric Reliability Council, is an agency put in place to ensure the reliability of the power grid in North America. NERC measures reliability of the power grid by four indicators: resource adequacy, transmission performance and availability, generation performance and availability, and system protection and disturbance performance. (NERC, 2020) This paper will focus on resource adequacy and generation performance and availability as measures of reliability as only generation and fuel supply impacts will be examined in this paper.

2.2.1 Resource adequacy

NERC measures resource adequacy by calculating a planning reserve margin. The planning reserve margin compares “committed capacity” to “net internal demand”. Each regional entity has a different reference margin level based on their own regulatory requirements, however minimum reserve margins required by NERC are 10 for predominately hydro systems and 15 for predominately thermal systems (NERC, 2020). A reserve margin can indicate how much additional reserve capacity may be needed in the event of a generator or fuel supply issue. Renewable energy sources are becoming a larger share of electricity generation in the US (Cochran et al., 2015). However, resources such as wind and solar, have the potential to bring an additional issue of ramping to the grid. As these resources are variable and their generation can fluctuate in a short timeframe, the rate of increasing or decreasing hourly load becomes pertinent (Craig et al., 2020). Periods of high ramps can require the use of reserves. In the case of ramping, flexible reserves would provide the additional capacity to meet these needs within a 60 minute timeframe (Cole et al., 2018).

A variety of technologies can provide these reserves, however each technology has different ramp rates (Cole et al., 2018). Flexible reserves are the types of reserves discussed in this paper that can provide additional generation in times when ramping is needed.

2.2.2 Generation performance and availability

WEFOR, weighted-equivalent generation forced outage rate, is a measure of the probability that a generating unit will be unable to generate at full capacity at any time, due to an outage or derating (NERC, 2020). There is seasonal variability in when certain fuels are most reliable. Natural gas, specifically, has higher WEFOR measures during colder winter months, illustrating the point that fuel supply is potentially affected by weather patterns (NERC, 2020). More variable or extreme weather patterns would then be likely to affect a generator's availability.

2.2.3 Current planning

NERC has identified "extreme natural events" as an emerging risk area pertaining to the reliability of the bulk power system (NERC, 2020). The recommendations to deal with extreme natural events effects on the grid are planning and modeling. According to the EDF, utilities currently plan only twenty years ahead when preparing for adjustments to their infrastructure, and most do not plan to harden their systems to withstand the effects of climate change (Webb et al., n.d.). A lack of certainty of the true effects of climate change on their system, as well as the lack of relevant data and the cost to enhance their system, are major obstacles to preparing for these changes (Webb et al., n.d.). Utilities that have started to implement these changes into their system have planned for effects such as storms and wildfires, however they are not planning for the more gradual effects of climate change, such as increased temperatures (Webb et al., n.d.). Climate change effects may require an increase in more diverse installed capacity throughout the country to meet demand needs and compensate for reduced capacity from climate change effects, and it is currently not being planned for throughout most of the US.

2.3 Relevance to Current Events

The negative impacts of climate change on the conventional grid have already been felt throughout the US. This section explores three examples from the last decade in which extreme weather events played a part in widespread power outages.

2.3.1 2011 and 2021 Texas outage

In February 2011, Texas and other southwestern states experienced sustained temperatures below freezing, leading to generation outages and multiple instances of load shedding. From February 2 to February 4, a total of 4.4 million customers were affected by the outages (FERC, 2011). The root cause of these rolling blackouts in Texas was the failure or derating of their generating units, half of which were due to the cold (FERC, 2011). The severe cold caused sensing and water lines at plants to freeze, automatically tripping units offline. Power plants in Texas are generally not winterized to the extent of those located in colder climates; most units are not enclosed as to reduce heat accumulation in the summer, leaving the equipment susceptible to freezing in winter. Recommendations were put in place for winterizing this infrastructure, however little was done. In February 2021, extreme cold temperatures, 30 degrees lower than average, again wreaked havoc on Texas' power grid, leaving 4.5 million customers in Texas without power. At its peak, about 40% of generation was offline in the state (Ball, 2021). Natural gas supply was reduced by almost half as water/other liquids present in raw natural gas froze at the wellhead or in gathering lines (York, 2021). The flow of gas ceased at the production stage and subsequently, along with increased demand because of the extreme temperatures, as well as additional plant outages, there was little fuel available to deliver directly to customers or generate electricity.

2.3.2 2020 California rolling blackouts

On August 14 and 15, 2020, a subset of California's population experienced rotating power outages. These affected about 500,000 customers on August 14th, and again on August 15th (Roth, 2020). It was the first occurrence of rolling blackouts due to insufficient capacity in California in almost twenty years (Gilbert & Bazilian, 2020). During this time, California was experiencing a record-breaking heat wave. With increasing penetration of solar that cannot generate electricity in the evening, and accelerated retirements of some fossil fuel generation, a lack of available generating resources combined with increased demand led to the need for load shedding to prevent more widespread outages (Roth, 2020). Multiple natural gas power plants tripped offline, likely from the high heat conditions, or were already out of service, likely from inadequate resource planning that did not anticipate the additional need for natural gas generation (Gilbert & Bazilian, 2020). As demonstrated in this case, long term management and planning is imperative to enhancing grid reliability.

2.3.3 Hurricane Maria in Puerto Rico

In September 2017, Hurricane Maria, a category 4 hurricane, hit Puerto Rico causing widespread damage and power outages for 1.5 million people (Gallucci, 2018). A combination of damage to power plants, substations, and transmission lines from high winds, flooding, and heavy rains led to the outages. These outages were not only widespread but lasted up to 180 days in some areas (Gallucci, 2018). Without power, markets, banks, and water treatment facilities were left inoperable, further exacerbating the living conditions of residents. Only 15% of Puerto Rico's transmission lines were designed for a category 4 hurricane, indicating how new climate trends and storm intensities are not currently being incorporated into energy infrastructure planning (Gallucci, 2018). The conventional grid is vulnerable to these changes and they can have devastating consequences, as they did in Puerto Rico.

2.4 State Profiles

Four states were chosen to analyze their 2050 forecasted generation. These states exhibit different load curves, electricity and natural gas uses, and were chosen because of their reliance on climate-vulnerable fuels or their energy policies. Figures 1 and 2 provide an overview of these states' use of electricity and natural gas.

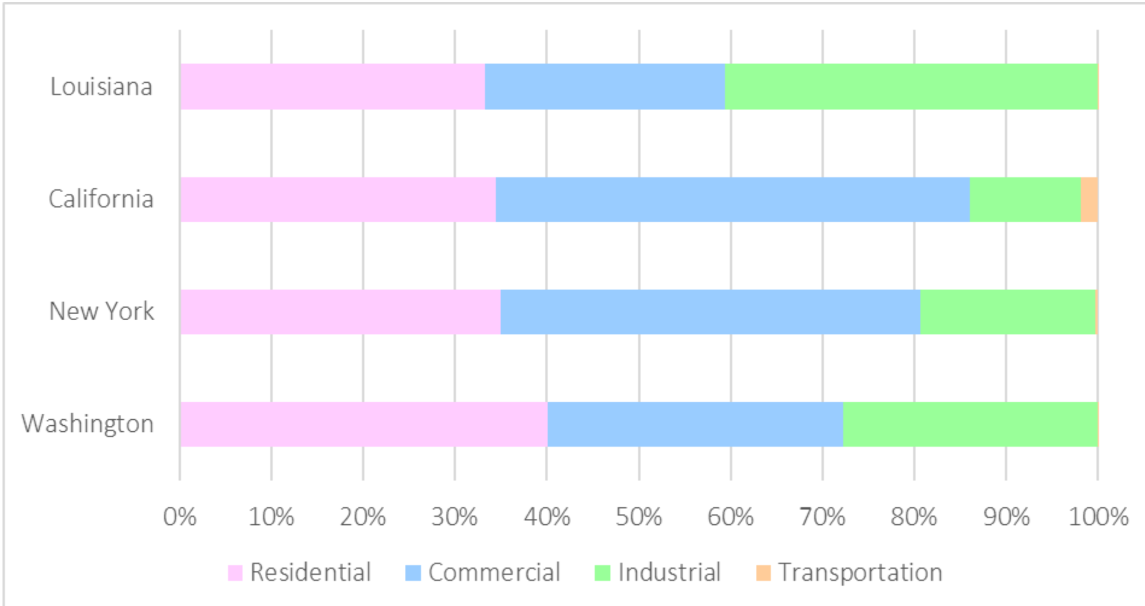


Figure 1. 2019 electricity purchases per state by end use sector. Calculations completed using EIA data.

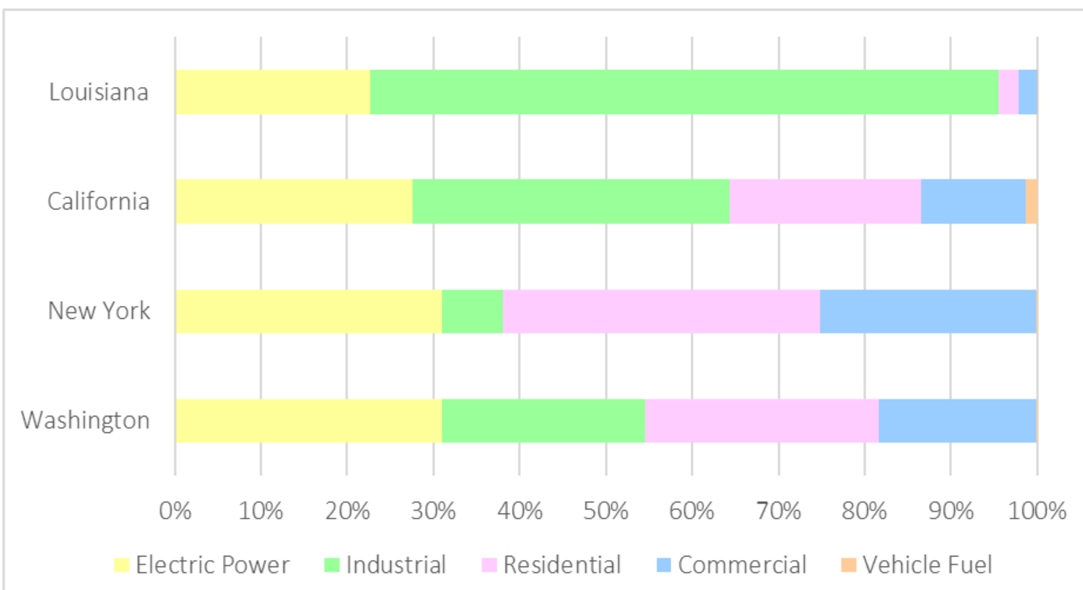


Figure 2. 2019 natural gas consumption per state by end use sector. Calculations completed using EIA data (EIA, 2019).

2.4.1 Louisiana

Louisiana has a robust industrial sector, which accounts for 60% of the natural gas consumption and 40% of electricity purchases in the state, making it the largest natural gas consumer per capita in the continental US (*Louisiana - State Energy Profile Analysis*, 2021). Although the state uses an average share of electricity in the residential sector, Louisiana has the highest per capita residential electricity consumption in the US, as the majority of homes' heating and cooling needs are met by electricity (*Louisiana - State Energy Profile Analysis*, 2021). Any grid outages are then likely to have a great impact on the residential and industrial sectors.

Louisiana's electricity generation is dominated by natural gas, Figure 3. Coal and nuclear also provide a large share of generation needs. The majority of Louisiana's thermal power plants are located along the Mississippi River. Renewables, such as solar, hydro, and biomass, consist of a small portion of capacity. Louisiana currently only has one hydroelectric plant, and one proposed hydroelectric plant set to come online in 2023 (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020). The state imports about 20% of its electricity needs from out of state.

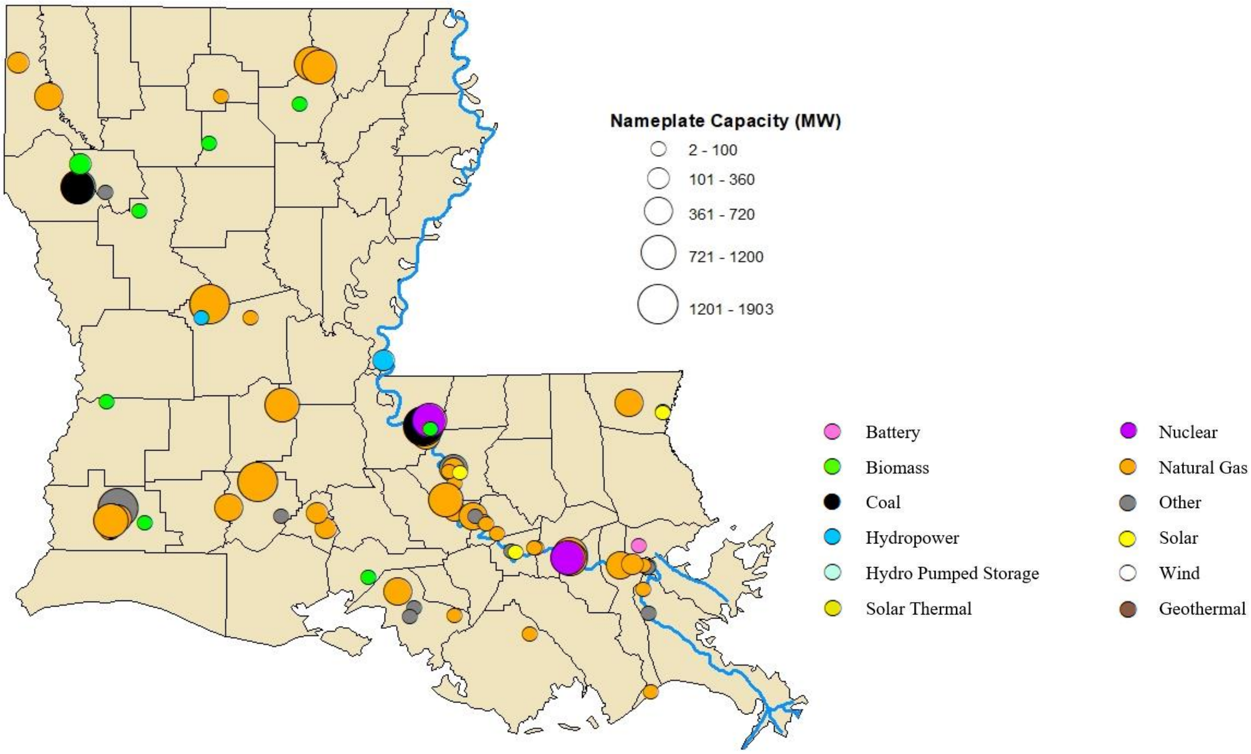


Figure 3. Projected (current and proposed) power plants in Louisiana in 2050 by fuel type and nameplate capacity. Mississippi River is shown in blue. Map is adapted from EIA form 860 (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020).

Louisiana is also home to the Henry Hub, which transports almost 2 billion cubic feet of gas per day. The hub connects 12 pipelines and sets the pricing for "natural gas physical and futures trading on the New York Mercantile Exchange"(*Louisiana - State Energy Profile Analysis*, 2021). Louisiana also produces natural gas; its largest producing area is the Haynesville shale formation. Assuming the state consumes gas produced instate primarily, it receives its remaining natural gas needs most likely from basins in Texas (Burns & Grubert, 2021). Therefore, an extreme temperature event across this region could impact natural gas production and natural gas fired-electricity production instate, as well as where Louisiana likely receives the majority of its out of state produced gas. For this analysis, I calculated impacts only on instate natural gas production or electricity generation.

Currently, Louisiana has no renewable portfolio standards or targets (*State Renewable Portfolio Standards and Goals*, n.d.).

2.4.2 California

California's commercial and residential sectors consume the majority of electricity in the state, Figure 1. California's industrial sector consumed the largest share of natural gas in the state. California produces little natural gas. It imports its gas from basins located in Canada, the southwest, and Rocky Mountain region (*California - State Energy Profile Analysis*, 2021).

California's 2050 projected power plants are dominated by solar and hydropower, Figure 4. Natural gas fired power plants also consist of a large share of electricity generation; 20% as of 2019 (*California - State Energy Profile Analysis*, 2021). The state's existing nuclear plants are scheduled to be retired by 2025 (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020). The state's hydroelectric plants, although they contribute a large share of overall capacity, have been variable in their actual generation in the past due to climate changes. As of 2019, the state received 28% of its electricity from out of state, mostly from the Pacific Northwest and Southwest (*California - State Energy Profile Analysis*, 2021). Climate change impacts in these regions can then affect the supply of electricity in California.

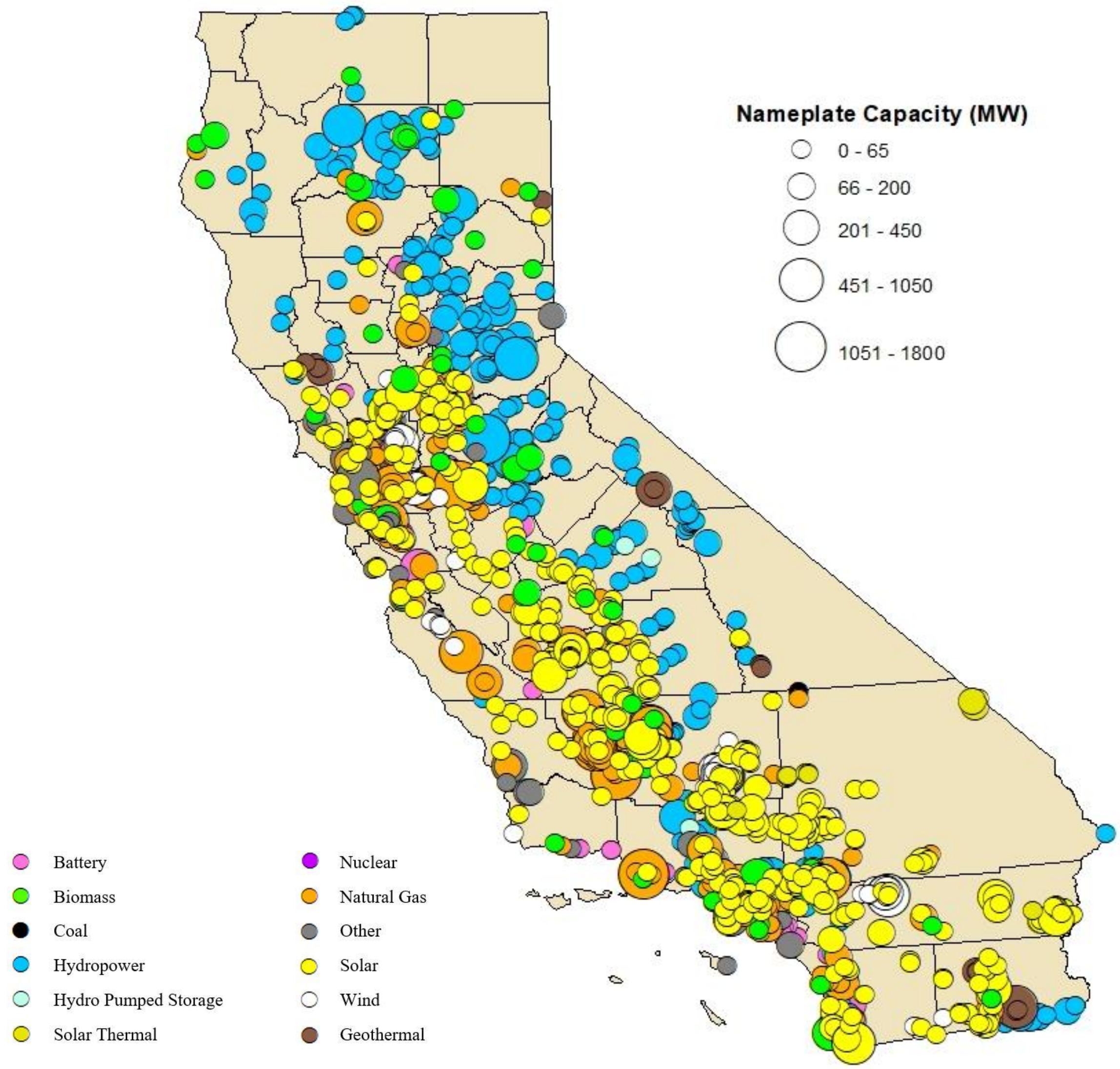


Figure 4. Projected (current and proposed) power plants in California in 2050 by fuel type and nameplate capacity. Map is adapted from EIA form 860 (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020).

California's utilities have begun to incorporate the effects of climate change into their resource planning. As of 2020, the California Public Utilities Commission has required utilities in the state to submit climate vulnerability studies of their service territory and infrastructure every four years (Webb et al., n.d.). California has also adopted a renewables portfolio standard in 2002. Currently, it requires that 60% of the state's electricity sales are to be from renewable sources by 2030 and for all electricity to originate from carbon free resources by 2045 (California Public Utilities Commission, n.d.).

2.4.3 New York

New York has one of the lowest per capita electricity consumption rates in the nation (*New York - State Energy Profile Analysis*, 2020). The commercial and residential sectors consume the most electricity, Figure 1, with the commercial sector accounting for almost 50% of electricity purchases.

New York does produce some natural gas, however the majority of natural gas is imported from Pennsylvania, specifically from the Appalachian basin (Burns & Grubert, 2021). Three out of every five households use natural gas for heating, as of 2019 (*New York - State Energy Profile Analysis*, 2020). With a majority of households in the state relying on natural gas directly for heating needs, a loss of supply from instate production, or neighboring states, specifically wells in the Appalachian basin, can cut off direct gas supply to households.

New York's projected power plants in 2050 consist of a large amount of natural gas and hydroelectric capacity, mostly in Long Island and along Lake Ontario, and small capacity wind and solar. New York's largest nuclear power plant at Indian Point, outside of New York, is set to retire in 2021, leaving three nuclear plants operating in the northern part of the state (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020).

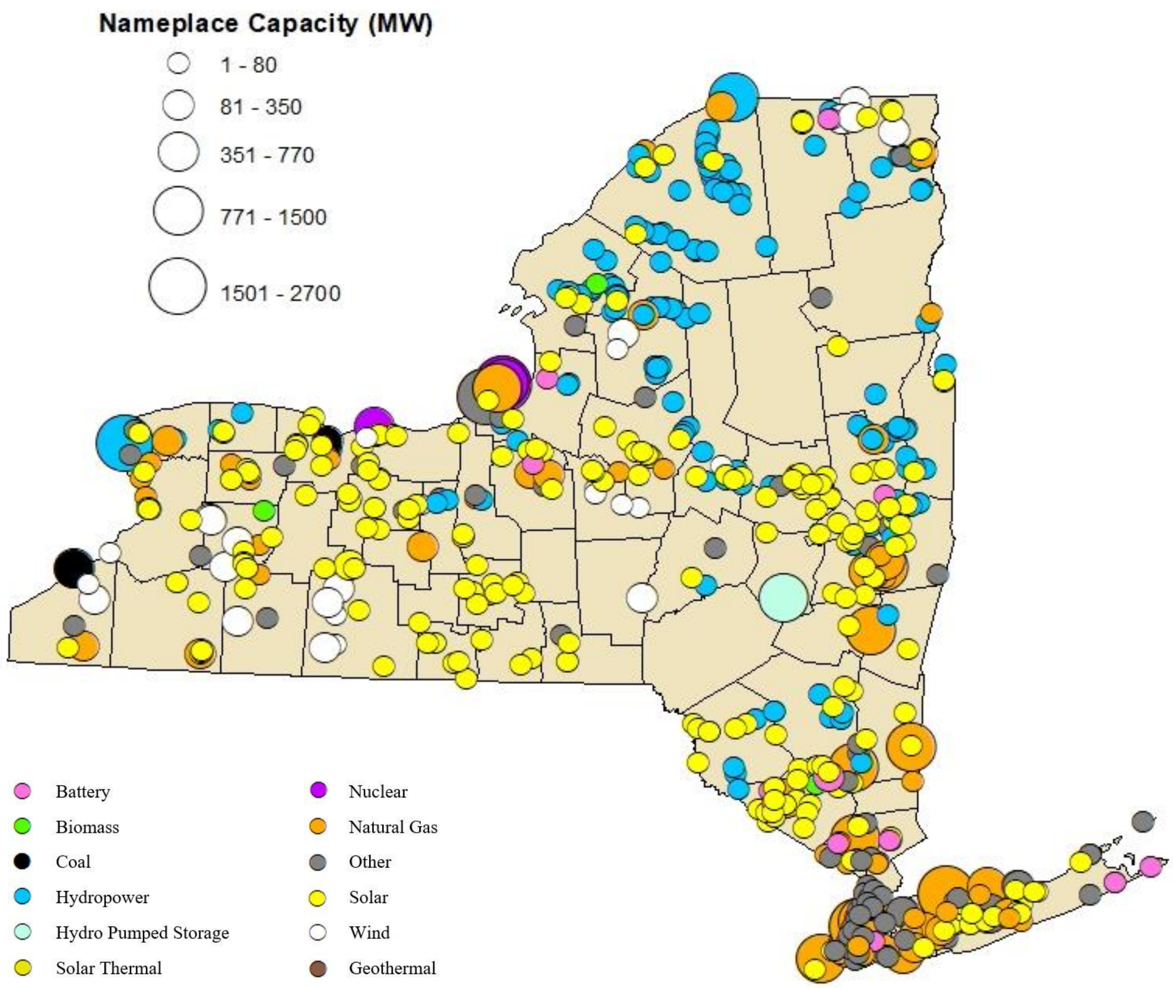


Figure 5. Projected (current and proposed) power plants in New York in 2050 by fuel type and nameplate capacity. Map is adapted from EIA form 860 (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020).

Con Edison, New York City's electric and gas provider, is one of few utilities to perform a comprehensive review of climate change effects on their infrastructure in their "Climate Vulnerability Study" (Webb et al., n.d.). Additionally, New York state adopted a Renewable Portfolio Standard in 2004 (NYSERDA, n.d.). The goal was to increase New

York's consumption of renewable energy. The goals have increased through the years, with the most recent standard being 70% of electricity must be produced by renewable sources by 2030 (NYSERDA, n.d.). New York plans to achieve this through offshore wind development; five offshore wind projects off of Long Island are currently in development, with an expected capacity of 4,300 MW (*New York's Offshore Wind Projects*, n.d.). New York is also assessing the ability of offshore wind in the Great Lakes region to provide additional capacity.

2.4.4 Washington

Washington is unique in that is relies very heavily on one fuel source: water. The state typically meets two-thirds of its electricity needs with hydropower (*Washington - State Energy Profile Analysis,* n.d.). The residential sector accounts for the largest share of electricity consumption, Figure 1.

Washington does not produce any natural gas and receives all of its natural gas from Canada (*Washington - State Energy Profile Analysis*, n.d.). The state consumes the majority of its natural gas to generate electricity and in the residential sector, largely to meet residents' heating needs, Figure 2.

In 2050, it is expected that hydropower will provide the most capacity, Figure 6. The majority of these plants are fed by the Columbia River. Smaller capacity wind and solar farms dot the southern part of the state. Natural gas fired power plants can be found in the western half of the state. Washington only has one nuclear plant, the Columbia nuclear plant along the Columbia River. The state's current two coal plants are scheduled to retire by 2025 (*Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)*, 2020).

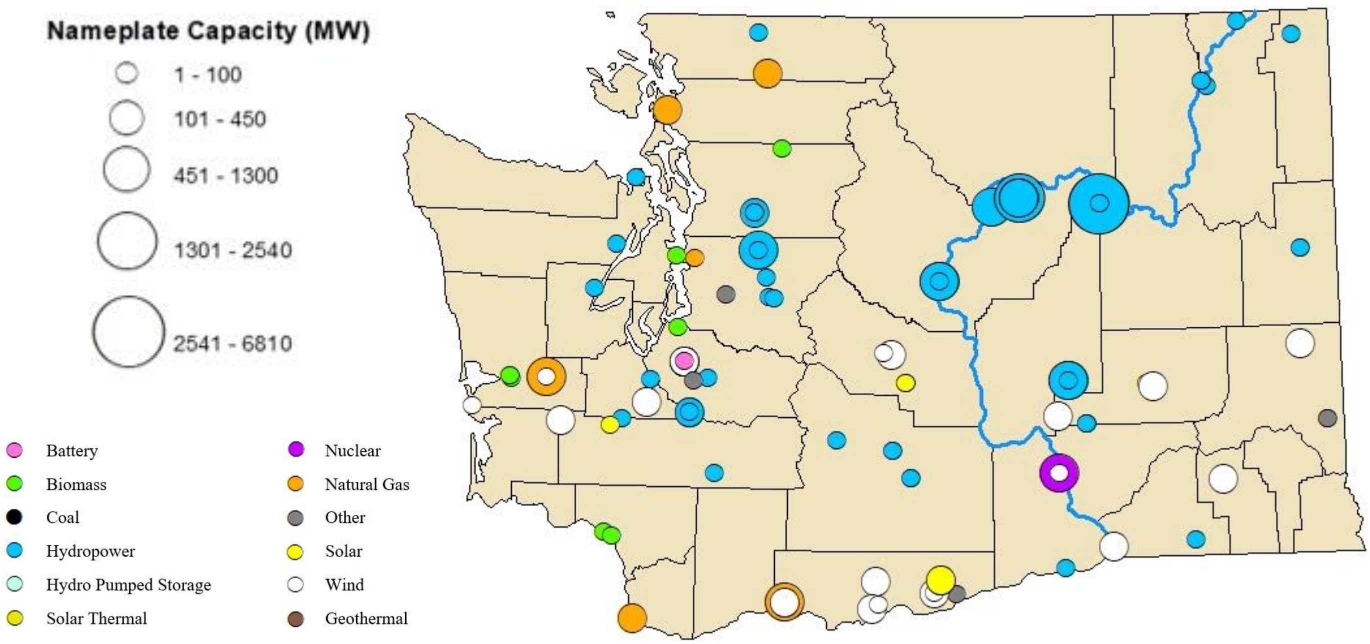


Figure 6. Projected (current and proposed) power plants in Washington in 2050 by fuel type and nameplate capacity. Columbia River is shown in blue. Map is adapted from EIA form 860

Washington adopted its renewable energy standard in 2006. Currently, its goals, as stated in the 2019 Clean Energy Transformation Act, require 100% clean electricity by 2045, in addition to the elimination of all coal electricity generation by 2025.

CHAPTER 3. METHODS

3.1 Outage Data

The first step in determining the effects of climate change on grid reliability included analyzing historical outage data. Archived data from the EIA, from 2002 through 2020, was analyzed to determine the root cause of all reported outages (*Electric Power Monthly*, n.d.). Based on information in chapter 2, the two main root causes of outages from potential climate change effects seem to stem from fuel supply or transmission issues. These keywords were searched in "Cause of outage". These outages were also identified by month they began, as well as hour of the day they began.

3.2 State Profiles

Specific states were chosen to be analyzed based on their electricity generation profiles. NREL's Cambium tool calculates the projected capacity and generation of various energy technologies in each state from 2020 to 2050 (*Cambium | Standard Scenarios 2020 | Cambium Scenarios (Hourly and Annual Data)*, n.d.). Note that this data is limited by all the potential errors and uncertainties associated with NREL's Cambium model. Additional data, such as electricity imports (electricity imported from out of state), is available by balancing authority. Cambium documentation provides information on which balancing authorities comprise each state (Gagnon et al., 2020). This data was combined by balancing authority to obtain a 2050 generation mix profile for each state. The year 2050 was chosen as it is assumed that climate change effects will be most pronounced during this time assuming a “business as usual” emissions scenario. Here, we define load as “busbar_load” in the NREL dataset and generation is defined as the sum of “Imports” and “Generation”.

The ability of a state to meet its loads with available generation is determined by calculating the planning reserve margin per hour. Although PRMs are generally calculated using peak capacity, in this case, hourly loads were used for the calculation, therefore hourly generation was assumed to be the “peak capacity” for that hour. See equation 1. Calculated PRMs were averaged for each hour of each month. PRMs were then averaged further for each hour of each season. Four seasons, summer (June, July, August), fall (September, October, November), winter (December, January, February), and spring (March, April, May), are used to assess trends.

$$Reserve\ magin = \frac{Generation\ (MWh) - Load(MWh)}{Load\ (MWh)} \times 100 \qquad (1)$$

To determine ramping needs, the percent difference of hourly loads was calculated, equation 2, where n is the hour of the day in which potential ramping needs are being assessed.

$$Ramping = \frac{Load_{n+1} - Load_n}{Load_n} \times 100 \qquad (2)$$

The amount of flexible reserves available to meet any ramping needs was calculated using the hourly flexible reserves for each state provided by NREL. Flexible reserves were averaged for each hour of each month, and then each hour of each season. They were divided by hourly average seasonal loads to calculate the amount of flexible reserves available as a percent of load. This was to determine how much flexible reserve, as a function of load, is available during each season throughout the day.

For extreme heat events, loss of capacity due to limited water availability and increased intake temperatures were calculated using values calculated by van Vliet, 2012. Thermal power plants with once through cooling systems are expected to experience a 12-16% reduction in capacity based on these effects from 2031-2060. Plants with recirculating cooling systems expect a 4.4-5.9% capacity reduction from 2031-2060. All technologies that are considered thermal were considered to be affected: nuclear, geothermal, biomass, natural gas, coal, and oil/gas/steam. Capacities for all plants were obtained from the NREL Cambium dataset. Reduced capacities for each technology were calculated for the minimum and maximum reductions of each cooling system scenario. If hourly generation exceeded the reduced capacity value, it was assumed the reduced capacity value was the actual amount generated that hour. Any hourly generation lower than the reduced capacity value was assumed to be generated that hour. New PRMs were then calculated with these reduced generation values to compare to original PRMs to determine the effects of these capacity reductions. These calculations were only performed for summer months when extreme heat events are most likely to occur.

Similar calculations were done to calculate the effects of extreme heat on natural gas combined cycle power plants. It is estimated that thermal power plants will experience a 1-2% capacity loss per 1°C increase in temperature (Sieber, 2013). All states have little thermal power plant capacity in 2050 except natural gas combined cycle plants so only these plants were analyzed. Assuming a capacity loss of 2% per degree Celsius, and an average summer temperature of 90°F, an eight degree Celsius increase is equivalent to a temperature of 105°F and reduced capacity of 16%. These calculations were only performed for summer months when extreme heat events are most likely to occur.

Increased electricity demand due to extreme heat was also incorporated. Louisiana’s maximum increase in electricity demand in 2050 due to heat is 35.8% (Allen et al., 2016). California, New York, and Washington’s worst case scenario 2050 increase in electricity demand is 9, 7.5, and 4.5% respectively (McFarland et al., 2015). If hourly generation exceeded the reduced capacity value, it was assumed the reduced capacity value was the actual amount generated that hour. Any hourly generation lower than the reduced capacity value was assumed to be generated that hour. New PRMs were calculated to determine the impact of these effects on each state’s reserve margins.

For hydroelectric power plants, calculations from a previous study indicating projected hydropower generation reductions seasonally in 2050, in different regions of the US, were used (Boehlert et al., 2016). This work specified generation reductions for California. Reductions specified for the Mid Atlantic were used for New York. Similarly, reductions specified for the Pacific Northwest were used for Washington and reductions specified for the Lower Mississippi for Louisiana. The maximum generation reductions for each state were chosen and are specified in Table 1. The reductions calculated under the reference scenario, which specifies a “business as usual” emissions scenario, were used. These reductions were applied to the hourly generation data provided by NREL. New PRMs were calculated to determine the effect of hydropower generation reductions on each state’s reserve margins.

Table 1. Maximum projected percent reduction in hydropower generation for each state (Boehlert et al., 2016).

State	Season	Percent reduction in generation
Louisiana	Summer	-18%
California	Fall	-11%
	Summer	-6%
New York	Spring	-3%
Washington	Summer	-14%
	Fall	-5%

Vulnerabilities corresponding to the effects of extreme cold events on the natural gas fuel supply were identified by calculating the available generation to meet demand with a 50% natural gas supply loss. 1% of natural gas supply loss was assumed to correlate to a 1% decrease in natural gas combined cycle generation. New generation values with this loss were calculated and average PRMs were calculated seasonally. During the 2021 Texas extreme cold event, 45% of natural gas supply was lost due to freezing at the wellhead or in pipelines (York, 2021). 50% loss in this case is a realistic scenario. This supply loss was only attributed to natural gas electricity generated within the state; electricity imported from other states or abroad was assumed to not be affected.

Power plant information was obtained from EIA form 860 for 2019, the most recent year for which final data was available as of this writing (*Form EIA-860 Detailed Data with*

Previous Form Data (EIA-860A/860B), 2020, p. 860). Plant and generator data was aggregated to calculate nameplate capacity, fuel source, water source, and latitude/longitude of each plant. Specifically, data at the plant level includes the latitude/longitude and water source, while data at the generator level includes nameplate capacity, fuel source, proposed generators, and retirement dates. These two datasets were combined using each generators “Plant Code” to get the fuel type associated with each plant. Nameplate capacities of generators with the same plant code were summed to get the total nameplate capacity of each plant. According to EIA-860 information, which may be incomplete, generators that are planned to be retired before 2050 were eliminated and any generators proposed to be constructed prior to 2050 were included.

The power plant information was inputted to ArcGIS. Climate projection data from climatetoolbox.org was used to show regional variability in climate per state (University of California Merced, n.d.). These projections are an aggregation of 20 climate models. The projections are downscaled to 4 km resolution for the contiguous US. All projections were using the “Multi-model mean derived from 20 downscaled CMIP5 models” under the higher emissions (RCP 8.5) scenario from 2040-2069. The Representative Concentration Pathway, RCP 8.5, scenario is considered the worst-case scenario by the IPCC. It predicts a radiative forcing value of 8.5 W/m^2 in which emissions continue to rise in the 21^{st} century. Projected number of days with a heat index of 105°F or greater during summer months (June, July, and August) was used. River/stream shapefiles were obtained from ArcGIS Hub (*USA Rivers and Streams*, 2020).

CHAPTER 4. RESULTS

4.1 Outage Trends

Figures 7 through 9 depict archived outage data from EIA's Electric Power Monthly (*Electric Power Monthly*, n.d.). Figure 7 shows the number of outages by year per root cause: fuel supply or transmission.

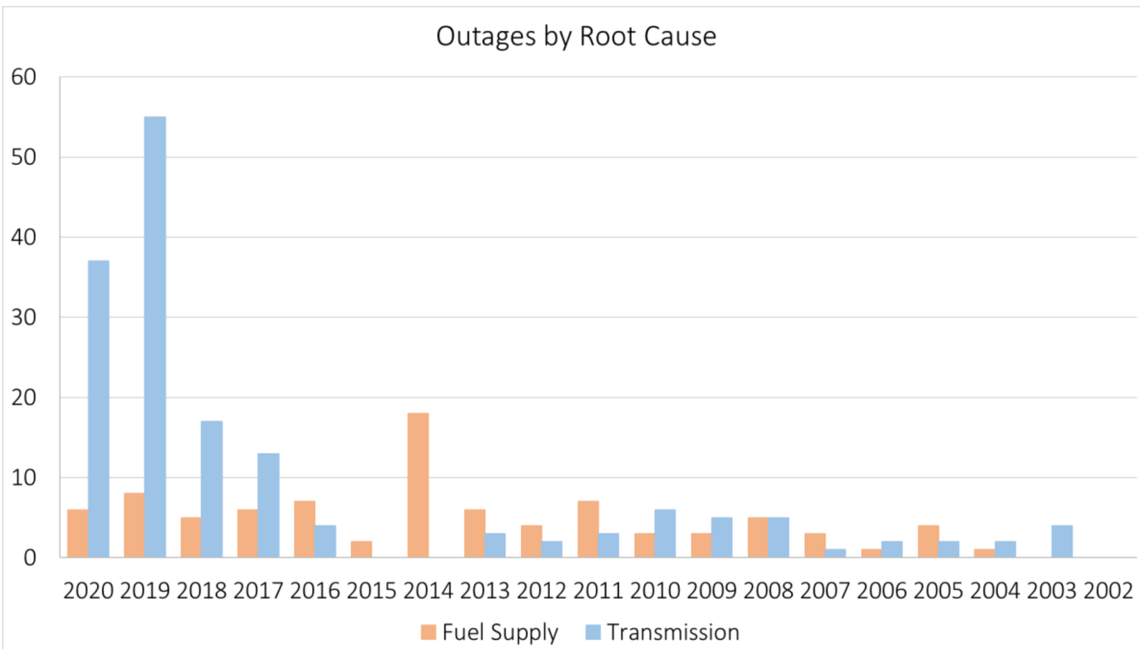


Figure 7. "Major disturbances" of the US power grid from 2002 through 2020. Data was collected from archived data from EIA's Electric Power Monthly. Orange indicates an outage caused by a fuel supply issue. Blue indicates an outage caused by a transmission issue.

Figure 8 utilizes the same data but aggregates the data by month and root cause.

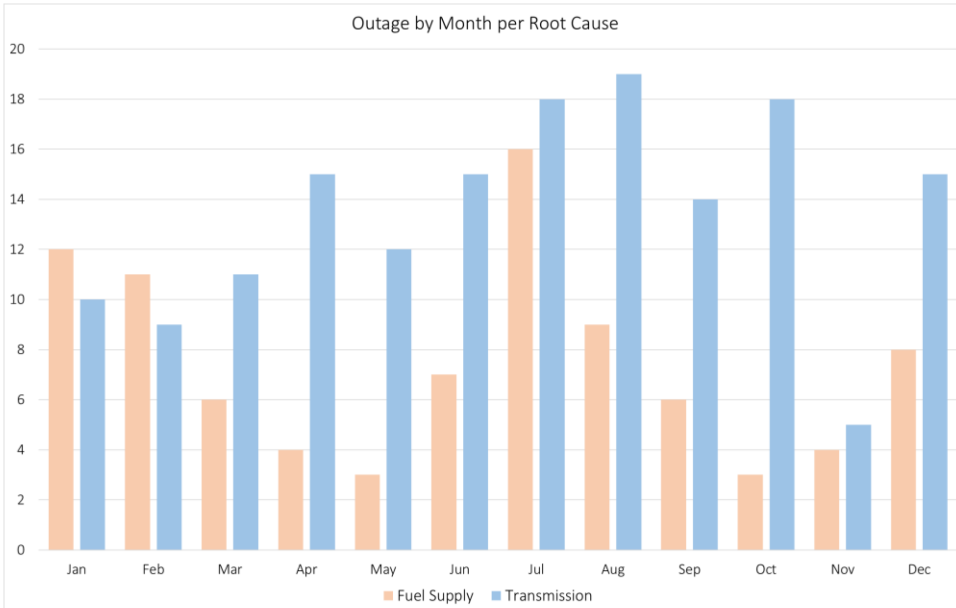


Figure 8. Outages from 2002-2020 per month by root cause: fuel supply or transmission. Data was collected from archived data from EIA's Electric Power Monthly. Orange indicates an outage caused by a fuel supply issue. Blue indicates an outage caused by a transmission issue.

Figure 9 utilizes the same data but aggregates the data by hour of the day.

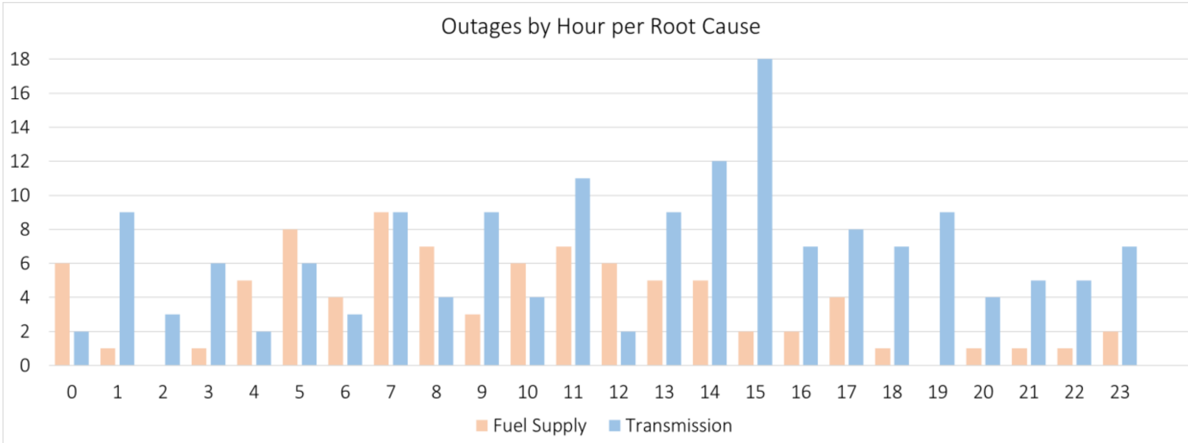


Figure 9. Outages from 2002-2020 per hour of the day by root cause: fuel supply or transmission. Data was collected from archived data from EIA’s Electric Power Monthly. Orange indicates an outage caused by a fuel supply issue. Blue indicates an outage caused by a transmission issue.

4.2 Case Studies

4.2.1 Seasonal patterns for all states

Figures 10 and 11 were compiled to assess each state’s projected typical load and reserve margin patterns in 2050.

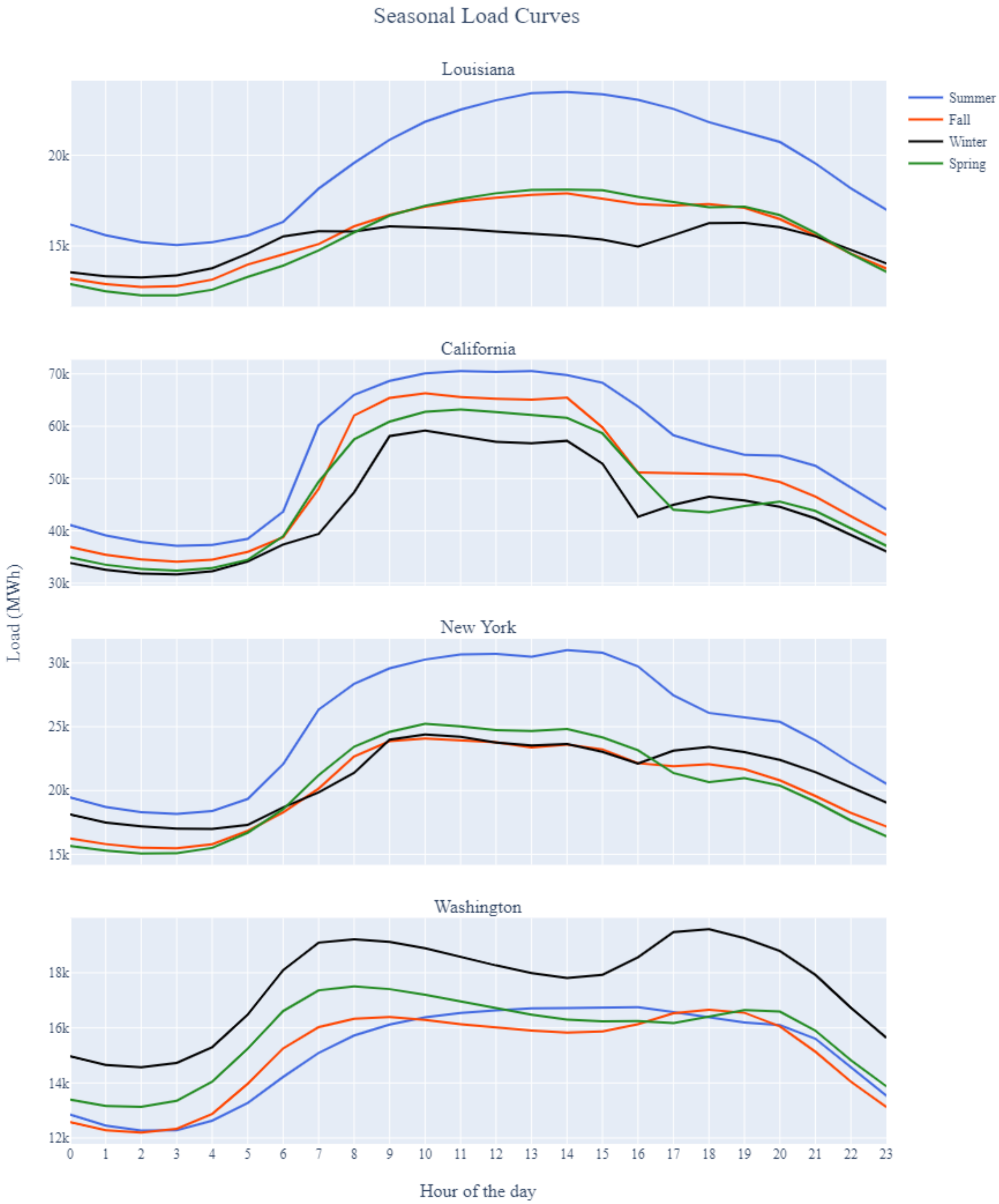


Figure 110. 2050 daily average seasonal loads. The load in MWh is plotted against each hour of the day, 0 through 23. Summer is indicated in blue, fall is indicated in red, winter is indicated in black, and spring is indicated in green.

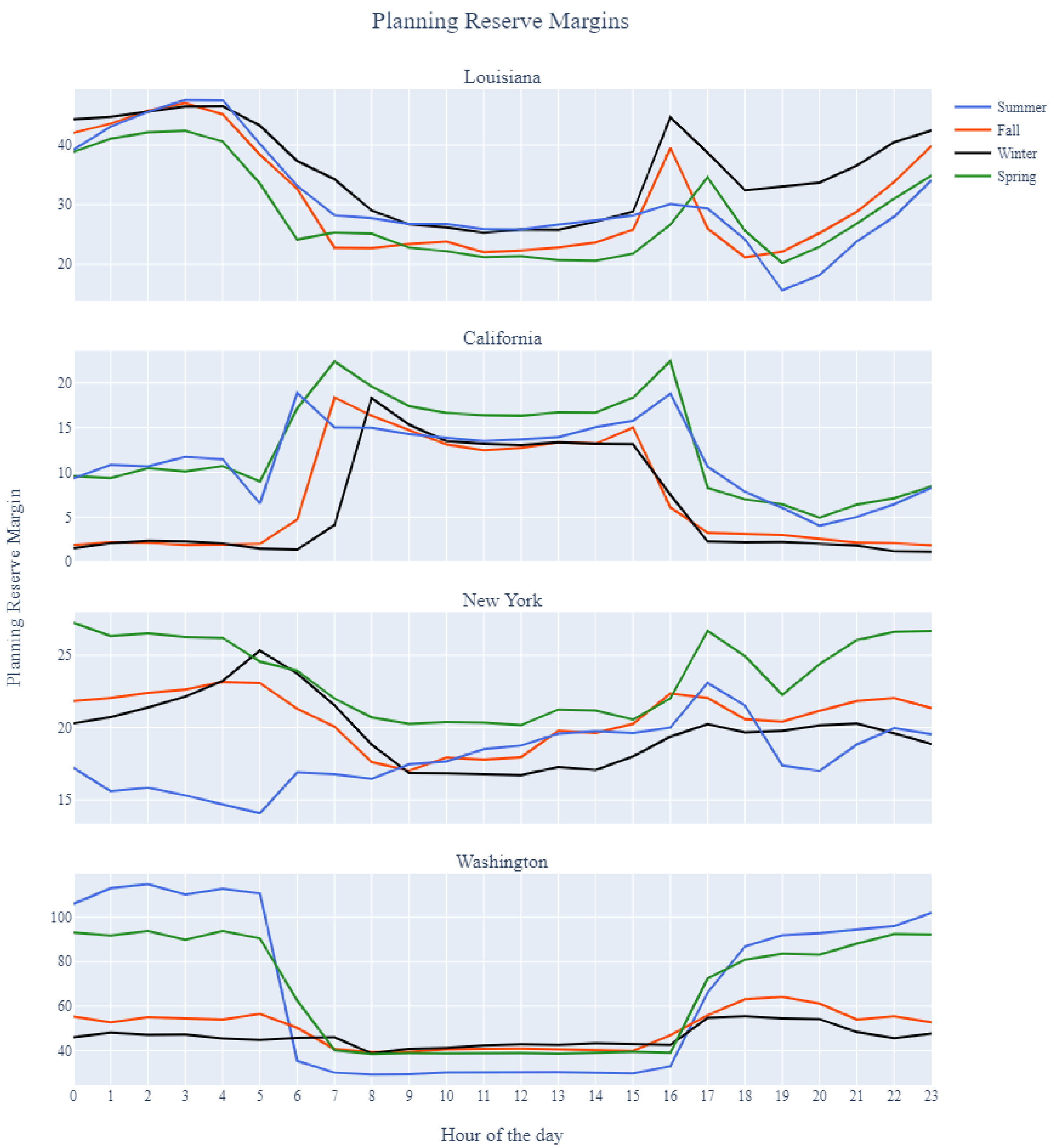


Figure 12. 2050 daily average seasonal planning reserve margins. The planning reserve margin is plotted against each hour of the day, 0 through 23. Summer is indicated in blue, fall is indicated in red, winter is indicated in black, and spring is indicated in green.

4.2.2 Potential ramping needs and available reserves

Figure 12 calculates the potential ramping needs using the formula described in the Methods section.

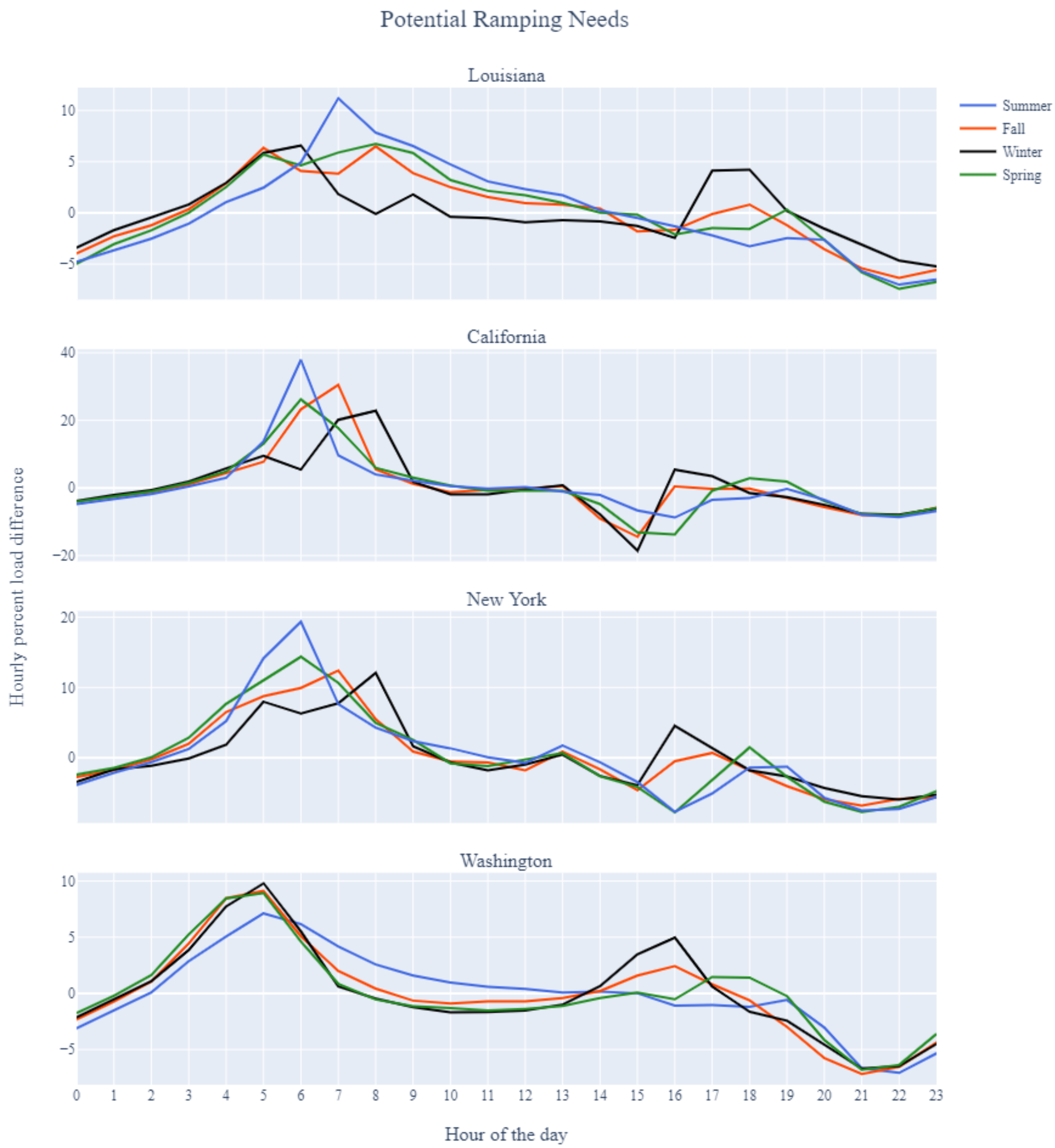


Figure 13. 2050 average daily seasonal potential ramping needs. The percent load difference per hour is plotted against each hour of the day, 0 through 23. Summer is indicated in blue, fall is indicated in red, winter is indicated in black, and spring is indicated in green.

Times in which ramping generation may be needed can be fulfilled with flexible reserves. The share of flexible reserves as a percentage of load is shown in Figure 13.

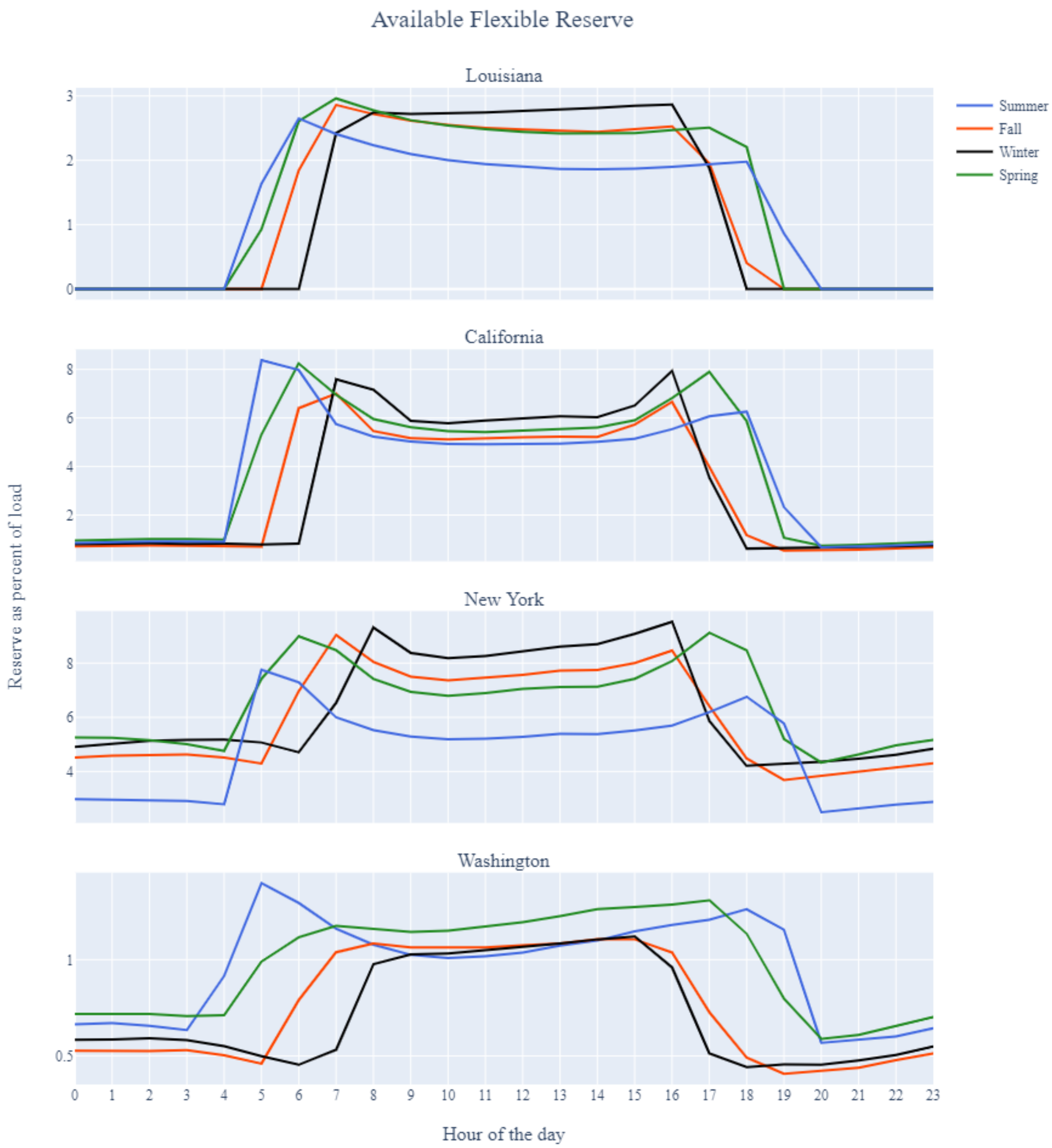


Figure 14. 2050 available flexible reserves to meet ramping needs, per season, per hour. Flexible reserve, as a percentage of load at that time, is plotted against each hour of the day, 0 through 23. Summer is indicated in blue, fall is indicated in red, winter is indicated in black, and spring is indicated in green.

4.2.3 Extreme heat impacts on thermoelectric power plants

Figure 14 shows the compounding effects of increased electricity demand and decreased natural gas combined cycle power plant capacity in the summer from extreme heat for each state.

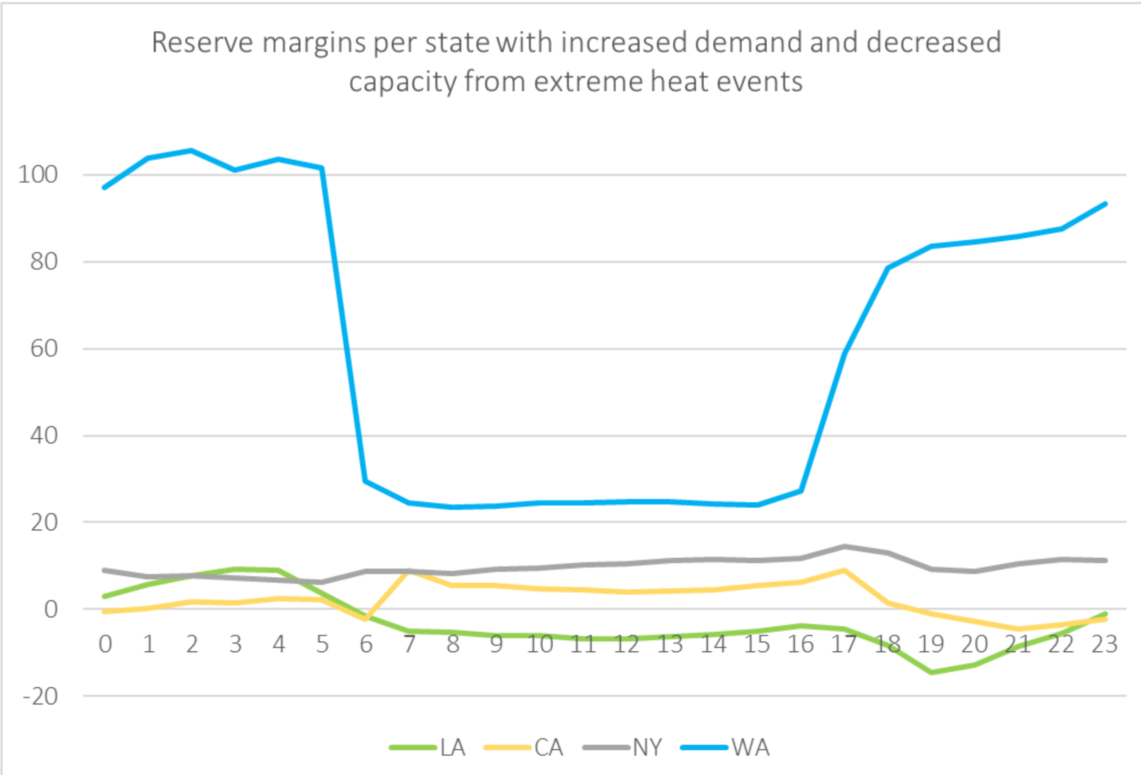


Figure 15. Average hourly summer reserve margins per state after accounting for increased demand and decreased natural gas combined cycle power plant capacity from extreme heat events. Louisiana is indicated in green, California is indicated in yellow, New York is indicated in gray, and Washington is indicated in blue.

Figures 15 and 16 show the regional variability of extreme heat in California and Louisiana.

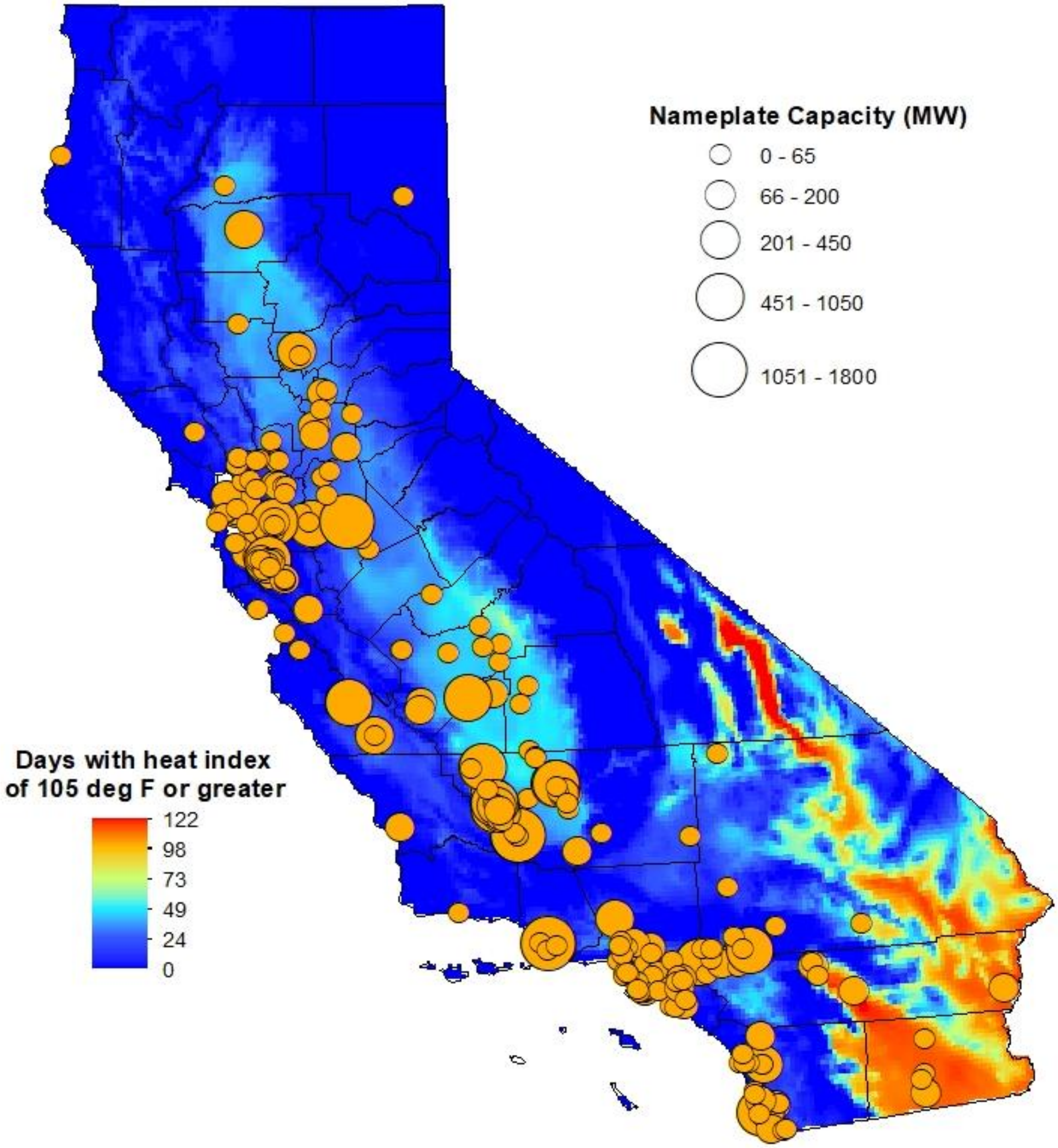


Figure 16. California's natural gas power plants (orange) by nameplate capacity and projected number of days in 2050 with a heat index of 105° F or greater. Projected heat index data was obtained from climatetoolbox.org.

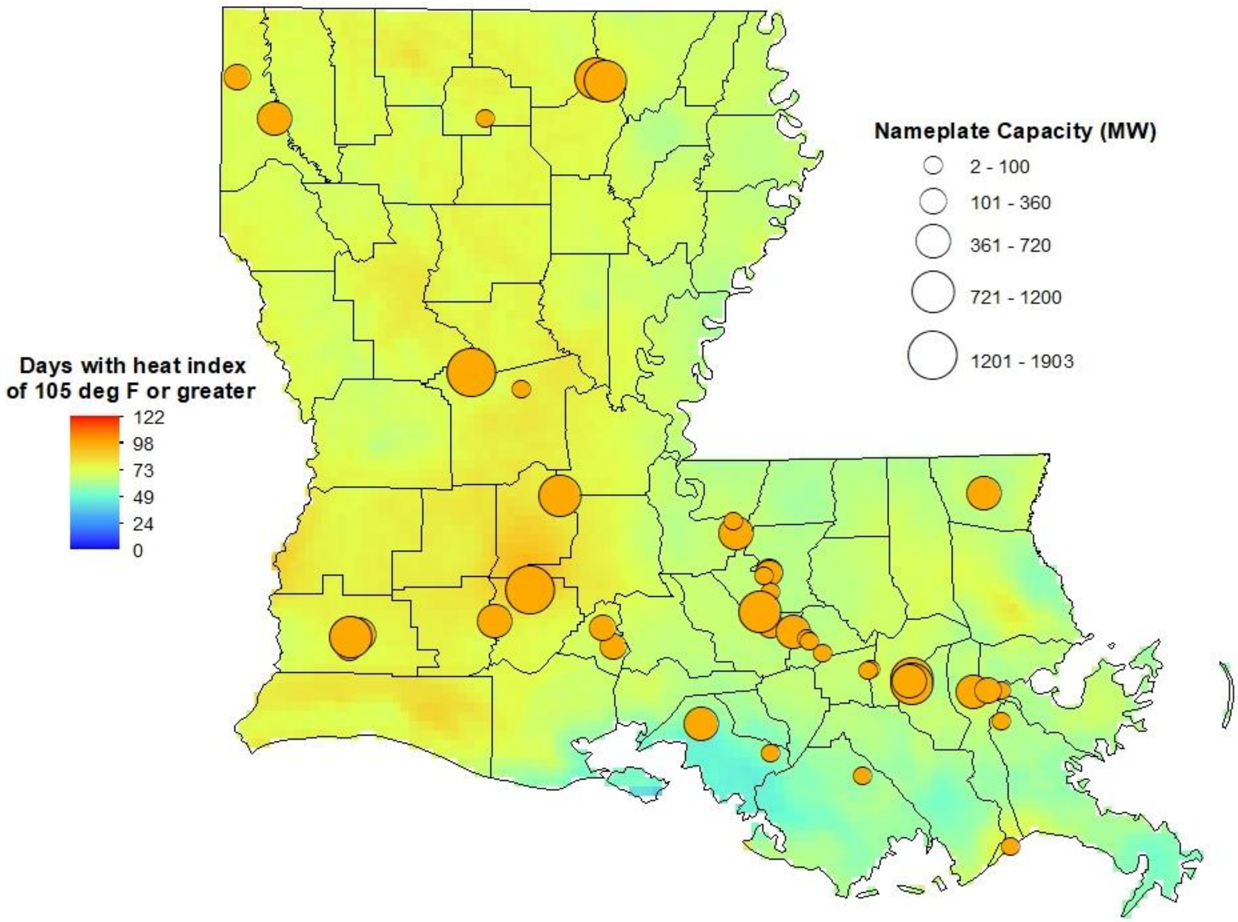


Figure 17. Louisiana's natural gas power plants (orange) by nameplate capacity and projected number of days in 2050 with a heat index of 105° F or greater. Projected heat index data was obtained from climatetoolbox.org.

4.2.4 Hydroelectric power plants

Figure 17 indicates the projected effects of reduced hydropower generation in the summer and fall for California and Washington.

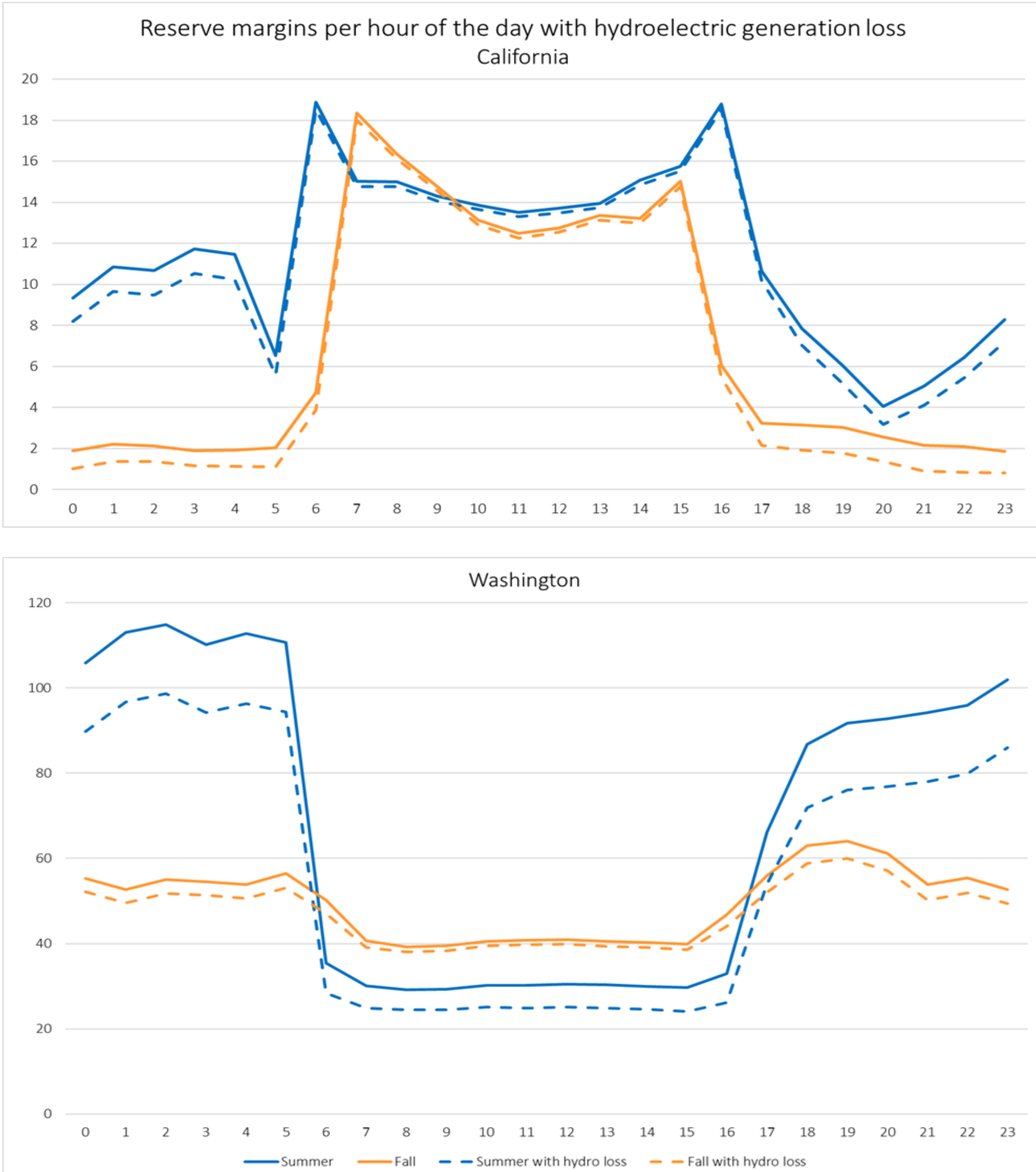
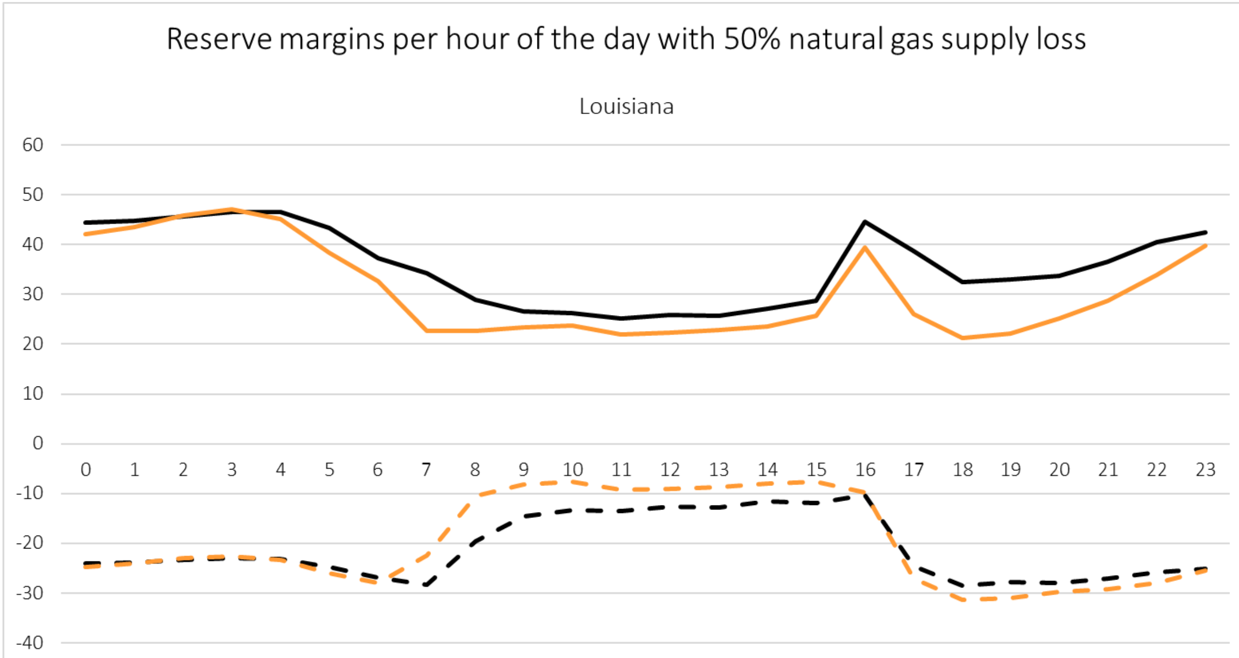
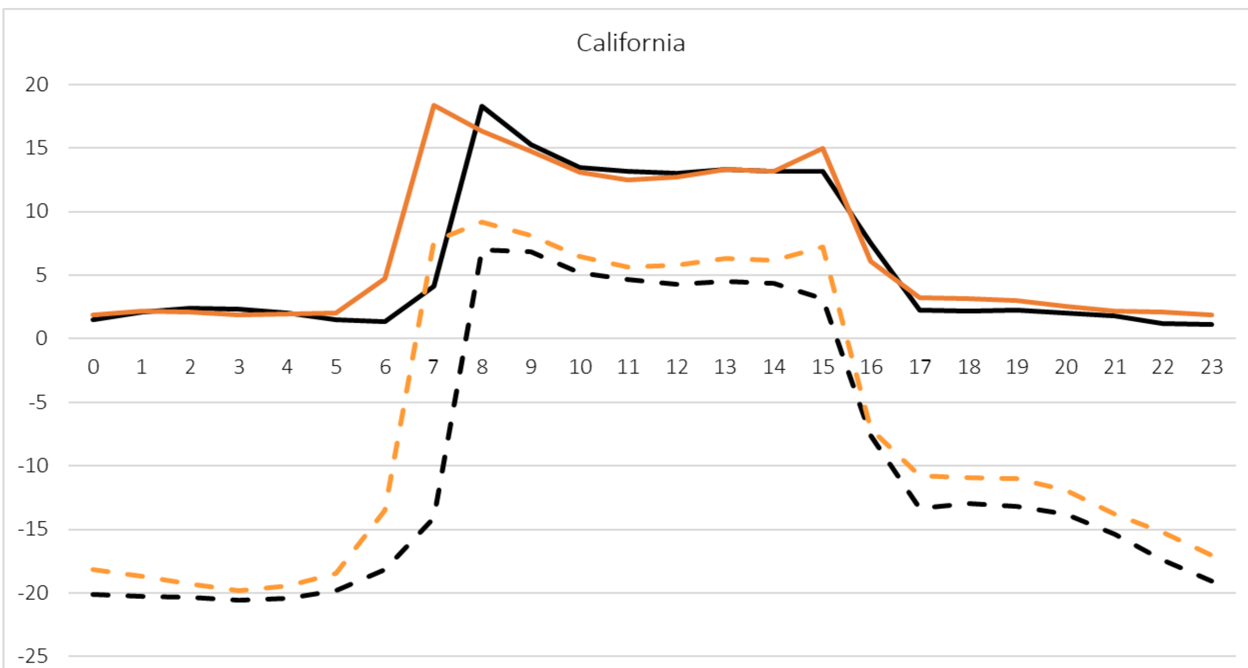


Figure 18. Average hourly reserve margins per season for California and Washington after accounting for projected 2050 decreases in hydropower generation according to the values outlined in Table 1. Reserve margins without any climate effects are indicated by solid lines. Reserve margins including decreased hydropower generation are indicated by dashed lines. Summer is indicated in blue. Fall is indicated in orange.

4.2.5 Extreme cold event effects on natural gas supply loss

Figure 18 depicts the projected effects of a 50% loss of natural gas supply for each state in the winter and fall.


Reserve margins per hour of the day with 50% natural gas supply loss
Louisiana
60
50
40
30
20
10
0
-10
-20
-30
-40
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23


California
20
15
10
5
0
-5
-10
-15
-20
-25
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23

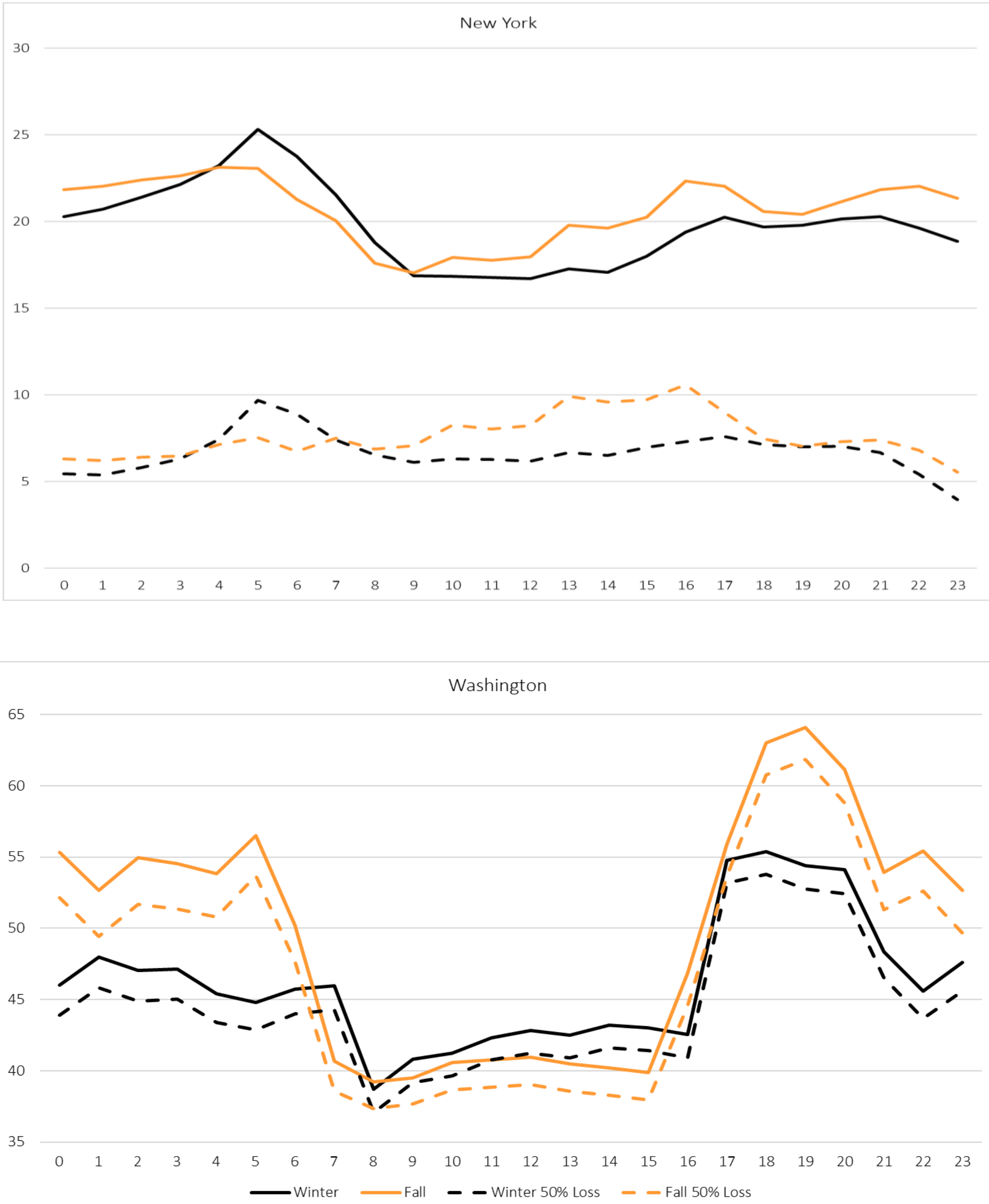


Figure 19. Projected average hourly reserve margins in winter and fall for all states after accounting for 50% loss in natural gas supply. Reserve margins without any climate effects are indicated by solid lines. Reserve margins including decreased hydropower generation are indicated by dashed lines. Winter is indicated in black. Fall is indicated in orange.

CHAPTER 5. DISCUSSION

This section will discuss the results depicted in chapter 4 to analyze how these climate effects may be impacting the future reliability of the conventional grid for Louisiana, California, New York, and Washington.

5.1 Trends in vulnerability from past outages

Outages in the US due to fuel supply or transmission issues have increased from 2002 to 2020, Figure 7. Transmission related outages have been increasing, specifically in the past five years, with fuel supply outages slightly increasing, but overall remaining steady. Historically, transmission related outages have peaked in July, August, and October, Figure 8. This time of year corresponds to hurricane season and increased storms. Fuel supply outages have historically peaked in January, February, and July, the times of year most likely to experience extreme heat or cold. Additionally, fuel supply related outages tend to begin in the morning hours, Figure 9. Extreme temperature events are when outages are most likely due to fuel supply, but also when electric demand is highest and most needed for its customers.

5.2 State Profiles

5.2.1 2050 projected load curves and planning reserve margins

Each state's projected load curve varies depending on their end use of electricity, whether that be in the residential, commercial, industrial, or transportation sectors (Hayes, 2013). Louisiana utilizes the largest share of electricity for the industrial sector (Figure 1), as illustrated in its projected load curve in Figure 10. Loads remain relatively steady throughout the day, except in summer. Louisiana's projected PRMs are highest in the winter, when it experiences its lowest loads., Figure 11, and are lowest during times of highest loads.

California and New York's commercial sector utilizes the largest share of electricity in each state (Figure 1). This is consistent with their seasonal load curves, Figure 10, in which loads rapidly increase in the morning, remain steady, and decline in the late afternoon (Figure 10). Based on California's projected PRMs (Figure 11), it is very vulnerable to any outages in the early morning and late evening hours of the fall and winter. Its highest PRMs correspond to the hours in which the state is likely to experience its highest loads, unlike in Louisiana. Overall, California has the lowest projected PRMs of all states analyzed.

New York's projected PRMs (Figure 11) are less consistent among seasons, with summer being most vulnerable throughout the day. There are not real hourly trends between seasons.

Washington's largest electricity user is the residential sector (Figure 1). Its load curve is consistent with typical load curves associated with the residential sector in that it has two load peaks: one in the morning and one in the evening. Washington has the highest overall projected PRMs, Figure 11. Winter and fall are the most vulnerable seasons with the lowest PRMs, however these are still much higher than those for other states, or the minimum NERC margins of 10 or 15 (NERC, 2020).

All states except Washington are projected to experience their highest loads during the summer. Washington sees its highest electric loads during the winter (Figure 10).

Outages more likely to happen during the summer would likely impact the most people in New York, California, and Louisiana because this time of year is when these states experience their peak loads. These higher loads indicate higher electricity demand. Washington, however, would be most vulnerable during the winter.

During the summer, extreme heat events will increase demand, stressing electrical equipment, and decreasing the efficiency of thermal power plants. Additionally, if these states are likely to experience drought or decreased precipitation during the summer, they are susceptible to generators shutting down from low water intake. These effects, compounded with the highest projected loads during the summer, can make the power grid in Louisiana, California, and New York vulnerable. On the other hand, extreme cold events could do the same in Washington. All states, except Louisiana, also have the smallest margins and are most vulnerable during the early morning and late evening hours. This is similar to the pattern seen in the historical outage data, Figure 9, in which fuel supply outages have historically occurred in the early morning hours.

5.2.2 Ramping

Figure 12 shows the different ramping needs of each state. All states have similar ramping patterns that are relatively consistent seasonally. Louisiana and Washington have the lowest potential ramping needs. Louisiana has steadier load curves, which is consistent with less potential for ramping needs. California has the most potential vulnerability for providing ramping generation as hourly loads differ between 20-40%, specifically between 7 – 10 AM. Summer consistently has the greatest load increases except in Washington state. In all states, ramping needs are highest in the morning hours, typically with another winter peak in the late afternoon.

Ramping is generally needed when a state has many generation resources that are variable. Wind and solar are considered variable sources as generation can fluctuate quickly based on changes in the weather (Craig et al., 2020). If there is a large increase in demand, certain generators will need to be able to come online to provide additional generation. California and New York are anticipated to have substantial wind and solar capacity in 2050, Figures 4 and 5. They also have the highest ramping needs, Figure 12. This could pose a potential problem in meeting demand in the future.

5.2.3 Reserves

Flexible reserves can fill the gap needed when demand increases quickly. Each state, except Louisiana in the early morning and late evenings, has some amount of flexible reserve available throughout the day, Figure 13. Seasonally, there are not consistent patterns between each state. California and New York have the greatest amount of reserves available, while Washington has the smallest reserves as a percentage of load. Louisiana and Washington, which have the lower reserves, also have smaller ramping needs. Flexible reserves are generally available in the morning hours in which ramping needs are highest for all states.

5.2.4 Extreme heat impacts on natural gas combined cycle plants

Extreme heat decreases the capacity of natural gas combined cycle power plants. Projected PRMs for each state in the summer are shown in Figure 14. These PRMs combined the effects of increased electricity demand due to extreme heat, as well as decreased capacity of natural gas combined cycle power plants due to extreme heat.

Louisiana is projected to be most affected by these effects, as its PRMs are negative from 6 AM through the rest of the day. California and New York also have lower PRMs, indicating that they are vulnerable to these compounded effects throughout the day. Washington is very minimally affected, and has sufficient additional capacity to maintain a high reserve margin.

Projected generation in the summer for these plants does exceed this reduced capacity in New York and Washington, however, California and Louisiana are more likely to be affected. If hourly loads remained similar to their baseline, this effect would be small (decreasing PRMs by <1). However, loads are likely to increase during an extreme heat event. There is much regional variability in these states' temperature patterns, Figures 15 and 16. Louisiana's entire natural gas fired power plant system is more likely to be affected by extreme heat, while only a small subset of California's natural gas plants in the southeast portion of the state are likely to experience heat indexes over 105° F. The majority of California's natural gas plants are located in regions with zero projected days of a heat index of 105° F or greater. Louisiana, however, has a projected minimum of 39 days per year with a heat index of 105° F or greater. Louisiana's natural gas plants are more likely to be affected by heat than California's.

5.2.5 Extreme heat and drought conditions on cooling water for thermal power plants

Thermal power plants are particularly susceptible to climate change effects as many rely on cooling water. As temperatures increase, increases in intake cooling water temperatures, especially from surface water sources, reduce the capacity of thermal power plants, as efficiency of the plant is decreased. Additionally, low stream flow, increases in drought conditions, and/or decreased precipitation, affect the water supply in rivers, lakes, reservoirs, etc. that are used for cooling water. Low cooling water supplies can also reduce the capacity of thermal power plants or shut them down completely. Depending on the cooling system used at the plant (once through or recirculating), low supply and increased temperatures of cooling water can reduce the capacity of thermal power plants from 4.4 – 16%.

Louisiana and Washington are similar in that only natural gas combined cycle plants with once through cooling systems would be affected by these capacity reductions. These effects are minimal compared to total generation.

In California, these reductions would impact natural gas combined cycle, geothermal, and biomass plants, however natural gas combined cycle plants would only be affected if they have once-through cooling systems. Capacity reductions to recirculation cooling systems were projected to be too small for natural gas combined cycle plants to affect generation.

In the worst-case scenario, 16% capacity reductions for thermal power plants, only New York's biomass plants, which provide a small portion of generation, would be affected.

The issue of increased cooling water temperatures and/or low cooling water supply is real, and should be planned for, however with proper resource planning, it is projected that in 2050 these states will have enough non-thermal electricity generation sources that these effects will be minimal.

5.2.6 Hydroelectric plants

Decreases in hydropower generation affect different states in different seasons.

Louisiana is minimally affected by any decreases in hydropower generation because it is projected to have a small amount of hydropower capacity. Louisiana's hydropower plants generate a maximum of 146 MWh in 2050. With an average generation of 21,416 MWh in 2050, any reduction in hydropower generation will have minimal effects overall.

California will experience slight decreases in their reserve margins during the summer and fall, Figure 17. However, reserve margins are already low in the early morning and late evening hours in the fall. A decrease in hydropower generation in the fall can make California's grid even more vulnerable to outages if there are additional issues.

New York is projected to react similarly to Louisiana. In 2050, New York's plants are projected to generate a maximum of 4,211 MWh, while the state's 2050 average generation is over 26,000 MWh. A 3% reduction in generation of hydropower in New York will have minimal effects on its overall ability to meet demand.

Washington continues to have high reserve margins with or without any decrease in hydropower generation in the summer or fall. However, the early morning and late evening hours in the summer are most affected by this decrease in hydropower generation.

5.2.7 Natural gas supply

A disruption in natural gas supply will affect those that use natural gas-fired electricity and those that use natural gas directly for other needs. All states consume about 20-30% of their natural gas supply for electricity generation (Figure 4). A loss of 50% natural gas supply will affect not only electricity generation, but customers that use processed natural gas directly. In Louisiana, this is overwhelmingly the industrial sector. Over 70% of Louisiana's natural gas is used in the industrial sector (Figure 5), therefore a disruption in supply would affect this sector more so than the residential or commercial sectors in the state. New York (Figure 5), however, consumes the most natural gas in the residential sector; a supply disruption would affect residents more so than the commercial or industrial sectors.

Louisiana is most severely affected by natural gas supply loss (Figure 18). During the winter and fall, a 50% loss ensures that there is not enough generation to meet load needs throughout the entire day.

California would also be left unable to meet its load needs from 3 PM until 7 AM. During this time, the extensive solar resources in California (Figure 4) would not be available without a storage system.

New York state would be affected, however not to the extent of Louisiana and California. If New York's other resources remain online, it is not likely to experience outages. Its reserve margins would be much lower, and it would be more susceptible to outages if some generation is lost.

Washington is the least affected. Its reserve margins slightly decrease with 50% gas supply loss; however they are still high enough that there is plenty of generation to meet its load needs. Washington however would be affected in sectors that use natural gas directly.

Besides the electric power sector, this is mostly the residential and commercial sectors (Figure 2).

5.3 Limitations

All calculations in this work are based on projected electricity load and generation estimates provided by NREL's Cambium dataset. These values are subject to all potential uncertainties and errors associated with their model. Any imported electricity and natural gas was assumed to not be affected by these climate change effects in these calculations. Only electricity generated instate was assumed to be affected by these climate effects. Additionally, all capacity reductions, generation reductions, increases in demand, etc. are subject to variability depending on the methods used to calculate these values. This work consistently used the worst-case emissions scenario to calculate worst case scenario effects. Depending on measures taken until 2050, this may not be an accurate reflection of greenhouse gas emissions at that time.

CHAPTER 6. CONCLUSION

The effects of future climate impacts on electricity generation and fuel supply vary geographically, seasonally, and hourly. These factors must be considered when planning to ensure the future reliability of the grid. Additionally, electricity outages may affect those differently in each state depending on the main use of electricity in the state. Similar is true for natural gas. Outages that affect more of the residential vs. industrial sector will have different social and economic impacts. Certain seasons or times of the day may contribute to more impactful outages than others. Regional variability in climate change effects is important and more work in states expecting more extreme weather must be done to quantify the potential effects on current energy infrastructure. Additional issues due to climate change, such as sea level rise and increased and more intense storms should also be assessed regionally to determine impacts on infrastructure. Each state studied, except Louisiana, currently has policies in effect to shift towards mostly renewable sources by 2050. These policies should only strengthen the resiliency of each state's grid, if planned correctly. However, as seen with California, that may not always be the case. Fuel mix also influences the future reliability of the grid. Heavy reliance on one particular fuel source, as seen in Louisiana with natural gas, or Washington with hydropower, may not imply that the state is susceptible to reliability issues, as Washington consistently had the highest projected reserve margins in each case. A combination of renewable energy policy, shifts away from fossil fuel energy sources that are more susceptible to heat, cold, and drought effects, as well as robust planning to ensure adequate reserves during times of increasing loads will likely affect how resilient the power grid is in these states in the future.

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